July 31, 2026

BY ELECTRONIC FILING

The Honorable Debbie-Anne Reese, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: **Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Charge System-Backed Exports, Docket No. ER26-___-000**

Dear Secretary Reese:

Pursuant to Section 205 of the Federal Power Act ("Section 205"),[1] ISO New England Inc. (the "ISO" or "ISO-NE"), joined by the New England Power Pool ("NEPOOL") Participants Committee (together, the "Filing Parties"),[2] hereby submits to the Federal Energy Regulatory Commission (the "Commission") this transmittal letter and revisions to the ISO New England Transmission, Markets and Services Tariff ("Tariff")[3] to implement the ISO's System-Backed Export Charge proposal (the "Proposal"). These revisions are supported by the testimony, sponsored solely by the ISO, of Dr. Enrico De Magistris, an Economist for the ISO.[4]

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[1] 16 U.S.C. § 824d.

[2] Under New England's Regional Transmission Organization arrangements, the rights to make this filing of changes to the Tariff under Section 205 of the Federal Power Act are the ISO's. NEPOOL, through the Participants Committee and according to the Participant Agreement, provides the sole Participant Processes for advisory input on ISO-NE matters.

NEPOOL strongly supports the Tariff revisions reflected in this filing and accordingly joins in this Section 205 filing. NEPOOL's support reflects its vote supporting the proposed Tariff revisions but not on the entirety of the rationale articulated in this transmittal letter. Indeed, Participants do not vote on, and NEPOOL therefore does not take an institutional position on, the specific statements, characterization, rationales, and legal arguments set forth in Sections V and VI of this transmittal letter. In general, the reasons behind a particular member's vote are not always uniform across the membership. Thus, Participants typically vote only on Tariff revisions and not on justifying rationale.

[3] Capitalized terms used but not otherwise defined in this filing have the meanings ascribed thereto in the Tariff, Second Restated NEPOOL Agreement, the Participants Agreement, and in the proposed Tariff revisions submitted as part of this filing ("Revised Tariff"). Market Rule 1 is Section III of the Tariff.

[4] *See* Testimony of Dr. Enrico De Magistris on Behalf of ISO New England Inc. ("De Magistris Testimony").

As addressed in Section VI of this transmittal letter, the ISO requests an effective date of October 1, 2026 for the proposed Tariff revisions to implement the System-Backed Export Charge proposal.

I. DESCRIPTION OF THE FILING PARTIES AND COMMUNICATIONS

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

The signatories to the New England Power Pool Agreement, which was first entered into in 1971, are referred to collectively as "NEPOOL." Currently, there are more than 560 signatories, which are referred to either as "Participants" or "members." They include all the electric utilities rendering or receiving services under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers (including owners of distributed generation and aggregators of such generation), developers, end users, and merchant transmission providers. Pursuant to revised governance provisions the Commission accepted,[5] the Participants act through the NEPOOL Participants Committee. Specifically, Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement authorize the Participants Committee to represent NEPOOL in proceedings before the Commission. Through the Commission-approved Participant Processes, NEPOOL is the vehicle through which all stakeholders with business interests in New England are able to provide informed input and advice to ISO-NE.

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

Kelly Caiazzo, Esq.*
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
Tel: (413) 540-4610
Email: kcaiazzo@iso-ne.com

[5] *ISO New England Inc.*, 109 FERC ¶ 61,147 (2004).

And to NEPOOL as follows:

Benjamin Griffiths, Vice-Chair*
NEPOOL Markets Committee
NRG Business Marketing, LLC
800 Carnegie Center
Princeton, NJ 08540
Tel: (781) 650-0320
E-mail: benjamin.griffiths@nrg.com

Thomas W. Kaslow, Chair*
NEPOOL Budget and Finance Subcommittee
c/o FirstLight Power, Inc.
100 District Avenue, Suite 102
Burlington, MA 01803
Tel: (781) 653-4249
E-mail: Tom.Kaslow@firstlight.energy

Rosendo Garza, Jr., Esq.*
Sebastian Lombardi, Esq.
Day Pitney LLP
Goodwin Square
225 Asylum Street
Hartford, CT 06103
Tel: (860) 275-0660
Fax: (860) 881-2465
E-mail: rgarza@daypitney.com
slombardi@daypitney.com

*Persons designated for service.[6]

II. STANDARD OF REVIEW

These Tariff changes are being submitted pursuant to Section 205, which "gives a utility the right to file rates and terms for services rendered with its assets."[7] Under Section 205, the Commission "plays 'an essentially passive and reactive' role"[8] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[9] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable – and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."[10] The changes proposed herein "need not be the only reasonable methodology, or even the most accurate."[11] As a result, even if an intervenor or the Commission

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

[7] *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002) (citation omitted).

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

[9] *Id.* at 9 (citations omitted).

[10] *Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984).

[11] *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995) (citation omitted).

develops an alternative proposal, the Commission must accept this Section 205 filing if it is just and reasonable.[12]

III. SUMMARY OF PROPOSAL

To better align the treatment of exports under the Pay for Performance ("PFP") market rules with the objective of incentivizing resource performance during scarcity conditions, the ISO proposes to charge net System-Backed Exports[13] the Performance Payment Rate ("PPR") during Capacity Scarcity Conditions ("CSC"). The ISO's Proposal implements recommendations from the ISO New England External Market Monitor ("EMM") and ISO New England Internal Market Monitor ("IMM") and addresses a potential "money-for-nothing" problem under the current rules.

In addition to proposing Tariff revisions to charge net System-Backed Exports the PPR during CSCs, the ISO's Proposal includes proposed Tariff revisions regarding: the allocation of System-Backed Export Charges, the removal of net System-Backed Export values from the calculation of the Capacity Balancing Ratio ("Balancing Ratio" or "BR"), the establishment of a System-Backed Export ("SBE") financial assurance requirement under ISO-NE's Financial Assurance Policy ("FAP"),[14] and a modification to ISO-NE's Billing Policy ("Billing Policy") to reference System-Backed Export Charges.[15]

IV. BACKGROUND

A. ISO New England's Pay for Performance Market Rules

ISO-NE's capacity market is a two-settlement market[16] in which resources may acquire a Capacity Supply Obligation ("CSO") through a capacity auction in exchange

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[12] *Cf. S. Cal. Edison Co.*, 73 FERC ¶ 61,219, at 61,608 n.73 (1995) ("Having found the Plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters." (citing *Cities of Bethany*, 727 F.2d at 1136)).

[13] As explained in Section V.C. of this transmittal letter, the ISO's proposed Tariff revisions define the scope of System-Backed Exports and calculate the System-Backed Export Charge based on the *net* System-Backed Export value.

[14] The FAP is Exhibit IA to Section I of the Tariff.

[15] The Billing Policy is Exhibit ID to Section I of the Tariff.

[16] The ISO also discusses the Pay for Performance market rules in two recent filings that are currently pending before the Commission. *See ISO New England Inc.*, Revisions to Change the Capacity Performance Payment Rate to $3,500 per MWh, Docket No. ER26-3047-000 ("Performance Payment Rate Revision Filing") (filed June 30, 2026); *ISO New England Inc.*, Docket No. EL25-106-000 Compliance Filing, Docket No. ER26-3213-000 ("Balancing Ratio Cap Compliance Filing") (filed July 21, 2026).

for monthly Capacity Base Payments.[17] Resources with a CSO have an obligation to provide energy and/or reserves to the ISO New England system during Capacity Scarcity Conditions in proportion to their share-of-system obligation, the product of their CSO and the Balancing Ratio.[18]

Negative deviations from a resource's share-of-system obligation during a CSC are assessed a monetary charge, and positive deviations are paid monetary payments. These performance charges and payments, called Capacity Performance Payments, constitute the second part of the two-settlement market system, and work as a transfer from resources performing below their share-of-system obligation to resources performing above their share-of-system obligation.[19] These additional charges or payments—in the form of a scarcity price adder on top of the energy market's scarcity pricing rules—during CSCs are designed to incentivize better performance during times of scarcity.[20]

B. Market Monitor Recommendations Regarding Treatment of Exports Under Pay for Performance

The ISO New England EMM and IMM have each made recommendations for changes to the treatment of exports under the Pay for Performance rules. Specifically, the EMM has identified "inefficient incentives for external transaction scheduling during shortage conditions" and recommended that the ISO "revise the PFP settlement rules to charge exporters the PFP rate during Capacity Scarcity Conditions."[21] The IMM agrees with the EMM's recommendation, stating that the ISO should update the Tariff to apply the Capacity Performance Payment Rate symmetrically to exports "aligning financial

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[17] *See* Tariff §§ III.13.7.1, III.15.8.1; De Magistris Testimony at 3; *see also New Eng. Power Generators Ass'n v. ISO New England Inc.*, 194 FERC ¶ 61,052, at P 2 (2026). The PFP market rules addressing Capacity Base Payments, Capacity Performance Payments, Monthly Capacity Payments and the stop-loss mechanism, and the allocation of Capacity Performance Payments are in Tariff Sections III.13.7.1, III.13.7.2, III.13.7.3, and III.13.7.4, respectively (for the Forward Capacity Market ("FCM")) and Tariff Sections III.15.8.1, III.15.8.2, III.15.8.3, and III.15.8.4, respectively (for the Annual Capacity Market). *See ISO New England Inc.*, 194 FERC ¶ 61,249, at P 1 (2026) (accepting Tariff revisions to replace the Forward Capacity Market with the Annual Capacity Market). The discussion of the PFP rules herein applies to both the Forward Capacity Market and the Annual Capacity Market unless otherwise noted.

[18] *See* Tariff §§ III.13.7.1, III.13.7.2, III.15.8.1, III.15.8.2; De Magistris Testimony at 3.

[19] *See* Tariff §§ III.13.7.2.6, III.13.7.4, III.15.8.2.6, III.15.8.4; De Magistris Testimony at 3–4.

[20] *See* De Magistris Testimony at 4–5.

[21] Potomac Economics, *2025 Assessment of the ISO New England Electricity Markets*, June 2025, at 64, *available at* https://www.iso-ne.com/static-assets/documents/100037/iso-ne-2025-emm-report-final.pdf.

incentives and ensuring that external transactions—whether imports or reduced exports—are valued equally for their contribution to system reliability."[22]

In response to comments in *New England Power Generators Association v. ISO New England Inc.*, Docket No. EL25-106-000,[23] the ISO stated that it plans to address the market monitors' recommendations in advance of the 2028–2029 Capacity Commitment Period.[24] The ISO's System-Backed Export Charge proposal implements these recommendations.

V. SYSTEM-BACKED EXPORT CHARGE PROPOSAL

A. Calculation of Capacity Performance Payments and Treatment of Exports Under the Current Pay for Performance Rules

As discussed above, under the PFP design, Capacity Performance Payments serve as the second settlement of the capacity market and work as transfers from underperforming resources to overperforming resources. To calculate Capacity Performance Payments, for each five-minute interval in which a Capacity Scarcity Condition exists, the ISO calculates, for each resource, whether or not the resource has a CSO, the resource's Capacity Performance Score ("CPS").[25] A Capacity Performance Score is the difference between the total amount of energy and reserves the resource provided to the New England Control Area (called "Actual Capacity Provided" or "ACP") and the resource's share-of-system obligation,[26] which is the product of the resource's CSO and the Balancing Ratio, the ratio of system load and reserve requirements during the CSC relative to the total CSO in New England.[27] As such, the Capacity Performance Score may be positive, zero, or negative, and reflects the resource's contribution to system reliability in the New England Control Area.[28] To calculate Capacity Performance Payments, the ISO multiplies the resource's Capacity Performance Score by the Capacity Performance Payment Rate.[29]

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[22] ISO-NE Internal Market Monitor, *2024 Annual Markets Report*, at 22–23, May 23, 2025, *available at* https://www.iso-ne.com/static-assets/documents/100023/2024-annual-markets-report.pdf.

[23] New Eng. Power Generators Ass'n v. ISO New England Inc., 194 FERC ¶ 61,052 (2026).

[24] *New Eng. Power Generators Ass'n v. ISO New England Inc*., Docket No. EL25-106-000, Response of ISO New England Inc., at 13–14 (filed September 19, 2025)

[25] *See* Tariff §§ III.13.7.2.4, III.13.7.2.6, III.15.8.2.4, III.15.8.2.6; De Magistris Testimony at 5.

[26] Stated in an equation, a resource's CPS = ACP − (CSO × BR). Tariff §§ III.13.7.2.4, III.15.8.2.4.

[27] *See* Tariff §§ III.13.7.2.3, III.13.7.2.4, III.15.8.2.3, III.15.8.2.4; De Magistris Testimony at 5–6.

[28] *See* Tariff §§ III.13.7.2.4, III.15.8.2.4; De Magistris Testimony at 6.

[29] *See* Tariff §§ III.13.7.2.6, III.15.8.2.6; De Magistris Testimony at 6.

The Tariff prescribes how to calculate the Actual Capacity Provided component of the Capacity Performance Score for each resource type, including the two types relevant to the System-Backed Export Charge proposal, generator resources and import resources.[30] The Tariff also sets a floor for the calculation of ACP at 0 MW.[31] For generator resources, for each five-minute interval in which a Capacity Scarcity Condition exists, Actual Capacity Provided is the sum of the resource's energy output during the interval and its Reserve Quantity for Settlement. If the resource is associated with one or more External Transaction sales, the resource will have its Actual Capacity Provided reduced by the hourly integrated delivered MW from all External Transaction sales, floored at 0.[32] For import resources, for each five-minute interval during which a Capacity Scarcity Condition exists, Actual Capacity Provided is the net energy delivered, that is, the sum of the External Transactions (sales and purchases) submitted by a Market Participant, floored at 0.[33]

Under the current rules, exports of energy out of the New England Control Area during a CSC can reduce a resource's Actual Capacity Provided, and, thus, in the case of a resource with a CSO, can lead to a negative Capacity Performance Score and negative Capacity Performance Payment when exports reduce a resource's contribution of energy and reserves below its share-of-system obligation.[34] However, since the Actual Capacity Provided floor is set at 0, exports that exceed a (CSO or non-CSO) resource's provision of energy and reserves to the New England system do not incur a PFP charge.[35]

To illustrate in examples:[36]

- If a Market Participant had a CSO of 100 MW, and, for each interval of a one-hour CSC, External Transaction purchases (imports) of 100 MW, and External Transaction sales (exports) of 10 MW, the resource's Actual Capacity Provided would be 90 MW, resulting (assuming, for simplicity, no reserves provided and a Balancing Ratio of 1.0) in a Capacity Performance Score of -10 MW (-10 MW = 90 MW ACP – [100 MW CSO

[30] *See* Tariff §§ III.13.7.2.2, III.15.8.2.2; De Magistris Testimony at 6–7.

[31] *See* Tariff §§ III.13.7.2.2, III.15.8.2.2 ("no resource shall have an Actual Capacity Provided that is less than zero"); De Magistris Testimony at 6.

[32] Tariff §§ III.13.7.2.2(a), III.15.8.2.2(a); De Magistris Testimony at 7.

[33] Tariff §§ III.13.7.2.2(b), III.15.8.2.2(b); De Magistris Testimony at 7. Where the ACP for import resources is based on the net energy delivered from all External Transaction sales and purchases, it is ultimately calculated at the Market Participant level.

[34] De Magistris Testimony at 9.

[35] *Id.* at 10.

[36] The examples are explained in the De Magistris Testimony at pages 9–10.

× 1 BR]), and a Capacity Performance Payment of $-93,370 (-10 × $9,337).[37]

- If, in a modified version of the previous example, the Market Participant had a CSO of 100 MW and External Transaction purchases (imports) of 100 MW but instead had External Transaction sales (exports) of 110 MW, the resource's Actual Capacity Provided would be 0 MW (not -10 MW, due to the 0 MW floor), resulting in a Capacity Performance Score of -100 MW (-100 MW = 0 MW ACP – [100 MW CSO × 1 BR]), and a Capacity Performance Payment of $-933,700 (-100 × $9,337), reflecting the 100 MW CSO that was not met. However, the additional 10 MW of net exports would not incur a PFP charge.
- Additionally, to illustrate another case, if a Market Participant had no CSO, and, for each interval of a one-hour CSC, no External Transaction purchases (imports), and External Transaction sales (exports) of 100 MW, the resource's Actual Capacity Provided would be 0 MW (not -100 MW, due to the 0 MW floor), resulting in a Capacity Performance Score of 0 MW (0 MW = 0 MW ACP – [0 MW CSO × 1 BR]), and no Capacity Performance Payment or charge.

These examples illustrate an asymmetry in the treatment of exports under the current design. Moreover, the participants in the latter two examples do not incur negative Capacity Performance Payments for the exports that exceed their contribution of energy and reserves to the system, even though those transactions export energy out of the New England Control Area during times of greatest system need.[38]

B. Rationale for Imposing System-Backed Export Charges

As Dr. De Magistris explains, the ISO is proposing to charge System-Backed Exports to address asymmetries in the current design.[39] First, the Proposal is designed to ensure that all exports receive the same treatment during a Capacity Scarcity Condition.[40] As noted above, exports that do *not* exceed a resource's contribution in terms of energy and reserves provided to the system are already accounted for in the PFP design because they reduce the resource's ACP, and therefore its Capacity Performance Payment. In contrast, because the ACP floor is set at 0, exports that *do* exceed the resource's energy

[37] Tariff §§ III.13.7.2.5, III.15.8.2.5.

[38] De Magistris Testimony at 11.

[39] *See id.* at 11–13.

[40] *See id.* at 11, 13.

and reserves are not accounted for.[41] There is no economic rationale for this asymmetry in treatment, and the proposed System-Backed Export Charge eliminates it.[42]

Additionally, imposing a charge on System-Backed Exports that exceed the energy and reserves that a resource contributes to the system aligns the treatment of such exports with imports, and with the Pay for Performance objective of incentivizing performance during scarcity conditions.[43] Correspondingly, the new charge eliminates a money-for-nothing problem created by setting the Actual Capacity Provided floor at 0, in which an exporting Market Participant and an importing Market Participant could coordinate their external transactions in a manner that would result in no net energy flowing yet result in a Capacity Performance Payment to the importing participant.[44]

To illustrate,[45] consider a scenario in which Market Participants A and B each do not have Capacity Supply Obligations. During an interval in which a CSC occurs, Market Participant A schedules 1 MW of exports and 0 MW of imports, while Market Participant B schedules 0 MW of exports and 1 MW of imports. Under current rules, A's exports are not charged the Performance Payment Rate, while B's imports have an Actual Capacity Provided of 1 MW, and thus receive the Performance Payment Rate. Overall, Market Participant A's and Market Participant B's imports and exports result in no flow of energy (at the system level, they net) but do result in a Capacity Performance Payment to B that A and B could share through an out-of-market agreement.[46] As explained in additional detail below, the ISO's Proposal addresses this money-for-nothing problem by imposing a System-Backed Export Charge on A's export, thereby eliminating the net Capacity Performance Payment for A's and B's transactions.[47]

C. Definition of System-Backed Exports and Calculation of System-Backed Export Charges

The ISO proposes new Tariff Sections III.13.7.2.A "System-Backed Export Charges" (for the Forward Capacity Market) and III.15.8.2.A "System-Backed Export

[41] *See* Tariff §§ III.13.7.2.2, III.15.8.2.2; De Magistris Testimony at 13.

[42] De Magistris Testimony at 13.

[43] *Id*.

[44] *See id.* at 13–14.

[45] This example is explained in the De Magistris Testimony at page 14.

[46] To the best of the ISO's knowledge, no Market Participant has engaged in this behavior.

[47] De Magistris Testimony at 14.

Charges" (for the Annual Capacity Market)[48] to define System-Backed Exports and set forth the calculation of System-Backed Export Charges.[49]

1. Definition of System Backed Exports

The ISO's Proposal defines System-Backed Exports as External Transaction sales that are either: (1) not associated with a generator, or (2) associated with a generator but exceeding the energy and reserves the generator provides. Specifically, Section III.13.7.2.A.1 of the Revised Tariff states:

> A System-Backed Export is an External Transaction submitted in accordance with Section III.1.10.7 or Section III.1.10.7.A[50] to export internal energy out of the New England Control Area by a Market Participant in the Real-Time Energy Market: (1) that is not associated with a generator; or (2) for External Transactions associated with a generator, for which the megawatt amount of the External Transaction sale(s) associated with the generator is greater than the sum of the resource's energy output plus the resource's Reserve Quantity For Settlement.[51]

As explained below, under the ISO's Proposal, exports that exceed the contribution of energy and reserves provided are charged the Performance Payment Rate during a CSC.[52] These exports are effectively backed by the whole New England system and are therefore subject to the proposed System-Backed Export Charge.[53] Exports that are backed by generation or offset by imports are not subject to a System-Backed Export Charge under the Proposal.[54]

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[48] The proposed new Tariff sections are reflected in the Table of Contents for Market Rule 1 in the Revised Tariff. Revised Tariff § III Table of Contents.

[49] The ISO's Proposal adds "System-Backed Export" and "System-Backed Export Charge" as defined terms in the Definitions Section of the Tariff. Revised Tariff § I.2.2. The Proposal also adds a reference to System-Backed Export Charges to Tariff Section 15(a) "Annual Capacity Market Overview." Revised Tariff § III.15(a).

[50] Sections III.1.10.7 and III.1.10.7.A of the Tariff address the submission of External Transactions and Coordinated External Transactions by Market Participants.

[51] *See also* Revised Tariff § III.15.8.2.A.1. The ISO's Proposal includes parallel changes to Section III.13 and Section III.15 of the Tariff. Additionally, as noted above, the ISO submitted to the Commission the Performance Payment Rate Revision Filing on June 30, 2026 and the Balancing Ratio Cap Compliance Filing on July 21, 2026. The proposed Tariff revisions for each of these pending filings are incorporated into the redline and clean Tariff documents as base text and are not shown as proposed revisions for the purpose of the present filing.

[52] *See* Revised Tariff §§ III.13.7.2.A.2, III.15.8.2.A.2; De Magistris Testimony at 12.

[53] *Id.*

[54] *See* Revised Tariff §§ III.13.7.2.A.2, III.15.8.2.A.2; De Magistris Testimony at 12–13.

2. Calculation of System-Backed Export Charges

Consistent with the calculation of Capacity Performance Payments for each resource and for each five-minute interval in which a Capacity Scarcity Condition occurs, the ISO proposes to calculate a System-Backed Export Charge for each five-minute interval in which a Capacity Scarcity Condition occurs for External Transactions associated with a generator and for External Transactions not associated with a generator.[55] For both types of System-Backed Exports, the System-Backed Export Charge equals the product of the net System-Backed Export value, calculated in accordance with the applicable formula described below, and the Capacity Performance Payment Rate.[56] Specifically, Section III.13.7.2.A.2 of the Revised Tariff states:

> For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a System-Backed Export Charge: (1) for External Transactions associated with a generator, for each resource that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval; and (2) for External Transactions not associated with a generator, for each Market Participant that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval. For each five-minute interval, the System-Backed Export Charge shall be equal to the net System-Backed Export value, calculated in accordance with the formulas set forth below, multiplied by the Capacity Performance Payment Rate, as defined in Section III.13.7.2.5.[57]

To calculate the net System-Backed Export value for External Transactions associated with a generator Section III.13.7.2.A.2 of the Revised Tariff provides the following formula:

> For External Transactions associated with a generator,
>
> net System-Backed Export value = the lesser of (the energy output of the generator in the interval + the Reserve Quantity for Settlement of the generator in the interval – the hourly integrated delivered MW for the External Transaction sale(s) associated with the generator) or 0.[58]

[55] *See* Tariff §§ III.13.7.2.6, III.15.8.2.6; Revised Tariff §§ III.13.7.2.A.2, III.15.8.2.A.2; De Magistris Testimony at 16–17, 20.

[56] Revised Tariff §§ III.13.7.2.A.2, III.15.8.2.A.2.

[57] *See also* Revised Tariff § III.15.8.2.A.2.

[58] *See also* Revised Tariff § III.15.8.2.A.2.

As explained above, exports associated with a generator reduce the generator's Actual Capacity Provided, but not below 0.[59] If an export of energy exceeds the energy and reserves provided by the generator (and are not accounted for in the ACP calculation), then the excess portion constitutes the net System-Backed Export value that is subject to the proposed charge.[60]

To calculate the net System-Backed Export value for External Transactions not associated with a generator, Section III.13.7.2.A.2 of the Revised Tariff provides the following formula:

> For External Transactions not associated with a generator,
>
> net System-Backed Export value = the lesser of (the hourly integrated delivered MW for the External Transaction purchase(s) of the Market Participant – the hourly integrated delivered MW for the External Transaction sale(s) of the Market Participant) or 0.[61]

As explained above, in calculating the Actual Capacity Provided for importing resources, the ISO nets the External Transaction purchases (imports) with the External Transaction sales (exports), up to the quantity where exports exceed imports.[62] If exports do exceed imports, the excess portion not accounted for in the ACP calculation constitutes the net System-Backed Export value that is subject to the proposed charge.[63]

For both External Transactions associated with a generator and External Transactions not associated with a generator, the net System-Backed Export value can be 0 or negative.[64] Therefore, when multiplied by the Capacity Performance Payment Rate, the net System-Backed Export value may result in a charge (when the value is negative) or no charge (when the value is 0), but it cannot result in a payment.[65]

D. Allocation of Capacity Performance Payments and System-Backed Export Charges

Under the PFP design, resources that perform below their share-of-system obligation during a CSC are charged a negative Capacity Performance Payment, and those negative Capacity Performance Payments are used to pay resources that perform

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[59] De Magistris Testimony at 18.

[60] *Id.*

[61] *See also* III.15.8.2.A.2. Consistent with the calculation of ACP for import resources, net System-Backed Export values for System-Backed Exports not associated with a generator are based on the net energy delivered and are calculated at the Market Participant level.

[62] De Magistris Testimony at 17.

[63] *Id.*

[64] *See* Revised Tariff §§ III.13.7.2.A.2, III.15.8.2.A.2.

[65] *See* De Magistris Testimony at 19 n.19.

above their share-of-system obligation, i.e., resources with positive Capacity Performance Payments.[66] Under the ISO's Proposal, the new System-Backed Export Charges will be added to negative Capacity Performance Payments and form a single pool of monies used to pay resources performing above their obligations.[67] In other words, where net System-Backed Exports impose a cost on the reliability of the system, the associated charges will be used to incent performance during times of greatest system need.[68]

In the proposed Tariff revisions, the phrase "and System-Backed Export Charges" is added to the title, introductory paragraph, and subsections (a) and (b) of Section III.13.7.4 "Allocation of Deficient or Excess Capacity Performance Payments" to reflect that that the Revised Tariff section addresses the allocation of deficient or excess Capacity Performance Payments and System-Backed Export Charges.[69]

Other than adding System-Backed Export Charges to the pool of funds addressed in subsections (a) and (b) of the Revised Tariff, the ISO is not proposing any changes to the allocation of deficient or excess Capacity Performance Payments.[70] In particular, the ISO is not proposing any changes to the stop-loss mechanism, and System-Backed Exports will not contribute to the accrual of negative Capacity Performance Payments used in the calculation of the monthly or annual stop-loss limit.[71]

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[66] *See* Tariff §§ III.13.7.2.6, III.13.7.4, III.15.8.2.6, III.15.8.4; De Magistris Testimony at 23.

[67] *See* Revised Tariff §§ III.13.7.4, III.15.8.4; De Magistris Testimony at 23.

[68] *See* De Magistris Testimony at 23.

[69] Revised Tariff § III.13.7.4. The proposed Tariff revisions include parallel changes to the title, introductory paragraph, and subsections (a) and (b) of Section III.15.8.4 "Allocation of Deficient or Excess Capacity Performance Payments." Revised Tariff § III.15.8.4. The Proposal also updates the Table of Contents of Market Rule 1 accordingly. Revised Tariff § III Table of Contents.

[70] Consistent with the allocation proposed in the Balancing Ratio Cap Compliance Filing, deficient (Capacity Performance Payments and System-Backed Export Charges) will be allocated to overperforming resources on a pro-rata, by positive Capacity Performance Score, basis, and excess (Capacity Performance Payments and System-Backed Export Charges) will be allocated to capacity resources on a pro-rata, by CSO MW, basis. *See* Revised Tariff §§ III.13.7.4, III.15.8.4; De Magistris Testimony at 24.

[71] *See* Tariff § III.13.7.3, III.15.8.3; Revised Tariff §§ III.13.7.4, III.15.8.4; De Magistris Testimony at 24–25 (explaining why including System-Backed Export Charges in the charges that can be stopped by the stop-loss mechanism would be contrary to the mutual insurance pool logic of the stop-loss mechanism); *see also New Eng. Power Generators Ass'n v. ISO New England Inc.*, 194 FERC ¶ 61,052, at P 82–83 (2026). Additionally, Revised Tariff Sections III.13.7.2.A.2 and III.15.8.2.A.2 state that unless otherwise expressly stated, "a System-Backed Export Charge shall not be treated as a Capacity Performance Payment under the Tariff." This statement further clarifies that System-Backed Exports are not included in the calculation of the sum of a resource's Capacity Performance Payments used in the stop-loss calculation.

E. Removal of System-Backed Exports from the Capacity Balancing Ratio

The ISO calculates the Capacity Balancing Ratio using the formula: (Load + Reserve Requirement) / Total Capacity Supply Obligation.[72] The ISO proposes to subtract the total net System-Backed Export values from the load component of the Capacity Balancing Ratio.[73] Specifically, the ISO proposes to modify Section III.13.7.2.3(a) as follows (red text reflects new language):

> (a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:
>
> Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) *minus the sum of all absolute*[74] *net System-Backed Export values calculated in accordance with the formulas set forth in Section III.13.7.2.A.2 in the New England Control Area during the interval*.
>
> Reserve Requirement = the Minimum Total Reserve Requirement during the interval.
>
> Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.[75]

The ISO's proposal to remove net System-Backed Export values from the Balancing Ratio aligns the treatment of exports in the calculation of the Balancing Ratio.[76] Under current rules, External Transaction sales that do not exceed a resource's contribution of energy and reserves to the system reduce the resource's Actual Capacity

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[72] Tariff §§ III.13.7.2.3, III.15.8.2.3. As noted above, the ISO's pending Balancing Ratio Cap Compliance Filing proposes to cap this value at 1.0.

[73] *See* Revised Tariff §§ III.13.7.2.3, III.15.8.2.3; De Magistris Testimony at 25.

[74] Because net System-Backed Export values can be zero or negative, the proposed revisions specify that the absolute value of all net System-Backed Export values will be subtracted from the load component of the Capacity Balancing Ratio.

[75] Revised Tariff § III.13.7.2.3(a); *see also* Revised Tariff § III.15.8.2.3(a). The ISO's Proposal includes applicable proposed revisions for each type of reserve deficiency that results in a Capacity Scarcity Condition. *See* Revised Tariff §§ III.13.7.2.3(b), III.13.7.2.3(c), III.15.8.2.3(b), III.15.8.2.3(c).

[76] *See* De Magistris Testimony at 25–26.

Provided and thus, mechanically, the Capacity Balancing Ratio.[77] However, because External Transaction sales that exceed a resource's contribution of energy and reserves to the system do not reduce a resource's Actual Capacity Provided, net System-Backed Exports are implicitly included in the numerator of the Capacity Balancing Ratio.[78] The ISO's proposed change addresses this asymmetry.[79]

F. Financial Assurance Policy Changes

As noted above, System-Backed Export Charges represent a new charge that Market Participants may incur during Capacity Scarcity Conditions. Consistent with the Financial Assurance Policy's collateralization requirements for potential exposure to negative Capacity Performance Payments, the ISO proposes to establish a new financial assurance requirement, SBE Financial Assurance, to mitigate the risk that a Market Participant incurs a System-Backed Export Charge but defaults on the payment when the invoice is due.

The ISO proposes to add a new subsection titled "SBE Financial Assurance" to Section VII "Additional Provisions for Forward Capacity Markets" of the FAP.[80] Under this subsection, any Market Participant with System-Backed Export transactions must include SBE Financial Assurance in the calculation of its FCM Financial Assurance Requirements described in Section VII of the FAP.[81] The subsection also sets forth the formula to calculate SBE Financial Assurance.

1. SBE Financial Assurance Formula

The ISO proposes to calculate the SBE Financial Assurance requirement using the following formula:

> SBE Financial Assurance = (PPR * SBE MW * Scarcity Hours) – MEC – PMEC[82]

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[77] *See* Tariff §§ III.13.7.2.2, III.13.7.2.3, III.15.8.2.2, III.15.8.2.3; De Magistris Testimony at 25–26.

[78] *See* Tariff §§ III.13.7.2.2, III.13.7.2.3, III.15.8.2.2, III.15.8.2.3; De Magistris Testimony at 26.

[79] *Id.* at 26. While the proposal to remove System-Backed Exports from the numerator of the Capacity Balancing Ratio does not modify the ISO's Balancing Ratio Cap Compliance Filing proposal, removing net SBE values from the numerator of the BR makes it mechanically less likely for the BR to reach the 1.0 cap. De Magistris Testimony at 26.

[80] *See* Revised Tariff, FAP § VII.C. This addition is reflected in the FAP Table of Contents in the Revised Tariff.

[81] *Id.* FAP § VII.C. The Proposal also adds language to the introductory paragraph of Section VII of the FAP make clear that the FCM Financial Assurance Requirements apply to any Market Participant with System-Backed Export transactions. *Id.* FAP § VII.

[82] *Id.* FAP § VII.C.

Generally, the first part of the formula, (PPR * SBE MW * Scarcity Hours), accounts for potential SBE Charges, while the other variables, MEC and PMEC, account for SBE Charges incurred within the prior or current month. Each component of the formula is explained more fully below.

a. PPR

PPR is the Performance Payment Rate as defined in Section III.13.7.2.5 and Section III.15.8.2.5 of Market Rule 1.[83]

b. SBE MW

The SBE MW component of the SBE Financial Assurance formula is based on the Market Participant's average SBE MWs across all CSCs occurring in the relevant group (summer, winter, or shoulder) of months over the last three Capacity Commitment Periods, along with the months within the relevant group for the current Capacity Commitment Period. The proposed SBE MW calculation is based on historic data, and, where the ISO does not currently impose System-Backed Export Charges, all data to date reflects a period in which the ISO did not charge net System-Backed Exports. Where the Proposal would, as of October 1, 2026 (the proposed effective date), impose System-Backed Export Charges, the incentives for transacting in System-Backed Exports are different under current rules than under the ISO's proposal.

Therefore, to account for the different incentives under the current rules and under the Proposal,[84] the SBE MW variable is bifurcated. For the period beginning on October 1, 2026, once there is a data point available from on or after October 1, 2026 for the relevant group of months (i.e., once a Capacity Scarcity Condition occurs in the relevant group of months), the formula will no longer utilize data from before October 1, 2026. After one CSC occurs in the relevant group of months, if an additional CSC occurs in the relevant group of months, the ISO would return to averaging SBE MWs for the relevant group of months over the last three Capacity Commitment Periods, along with the months within the relevant group for the current Capacity Commitment Period.

SBW MW is defined in the proposed revisions to the FAP as follows:

> SBE MW equals the Designated FCM Participant's average MW of System-Backed Exports across all Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data

[83] Revised Tariff, FAP § VII.C.

[84] The ISO makes the basic assumption that data from after the System-Backed Export Charge proposal is in effect would be more reflective of Market Participants' future behavior with respect to System-Backed Exports than data from before the Proposal was in effect.

> becomes available; provided, however, that, beginning on October 1, 2026, data from Capacity Scarcity Conditions that occurred prior to October 1, 2026 shall no longer be used once data is available from a Capacity Scarcity Condition in the relevant group of months in a prior Capacity Commitment Period or a Capacity Scarcity Condition in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.[85]

c. Scarcity Hours

The Scarcity Hours component is a measure of the likelihood of a Capacity Scarcity Condition occurring, based on the relevant group (summer, winter, or shoulder) of months, and is based on historic data. Scarcity Hours are defined in the proposed revisions to the FAP as follows:

> Scarcity Hours equals the highest total number of hours in which a Capacity Scarcity Condition occurred during any month within the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.[86]

d. MEC and PMEC

The MEC and PMEC components are estimates of the System-Backed Export Charges incurred in previous months and in the current month, respectively. They are expressed as subtractions from the formula because when they reflect a charge (a negative number) this will result in the SBE Financial Assurance increasing. MEC and PMEC are defined in the proposed revisions to the FAP as follows:

> MEC (monthly export charges) equals System-Backed Export charges incurred in previous months, which have not yet been invoiced in instances where the MEC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MEC is a charge to the Designated FCM Participant. The MEC is estimated from

[85] *Id.*

[86] *Id.*

> the first day of the current month until it is replaced by the actual settled MEC value when settlement is complete.[87]
>
> PMEC (preliminary export charges) equals estimated System-Backed Export charges incurred in the current month. Where the estimated System-Backed Export charges shall be updated three (3) days after publication of the applicable report on the Market Information Server.[88]

2. Modification to the Definition of Average Balancing Ratio

The ABR is the duration-weighted average of all of the system-wide Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months (summer, winter, shoulder) in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period.[89] In the FCM Delivery Financial Assurance formula, a resource's capacity weighted average performance is measured against the ABR, which represents a resource's share-of-system obligation. That calculation is one component used in determining a Market Participant's FCM Delivery Financial Assurance requirements.[90]

As addressed in Section V.E of this transmittal letter, the ISO is proposing to remove the total net System-Backed Export value from the calculation of the load component of the Balancing Ratio. Because the ABR calculation utilizes an historic "look back" at prior system-wide Balancing Ratios, it is necessary to specify whether, in performing that look back, the ISO will remove the total net System-Backed Export value from historic Balancing Ratio values associated with Capacity Scarcity Conditions that took place when the Balancing Ratio formula that does not subtract the total net System-Backed Export value was in effect. The ISO proposes to remove the total net System-Backed Export value from the calculations, because this would allow the FCM Delivery Financial Assurance calculation to more accurately capture the necessary collateral for the updated Pay for Performance rules (i.e., in which the total net System-Backed Export value is removed from the calculation of the load component of the Balancing Ratio).

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[87] *Id.*

[88] *Id*.

[89] *Id*. Section VII.A.1.

[90] *See ISO New England Inc.*, Revisions to Update Certain Definitions in the FCM Delivery Financial Assurance Formula, Docket No. ER25-2403, Transmittal Letter, at 5 (filed June 2, 2025) ("The ABR and CWAP [capacity weighted average performance] portion of the formula helps collateralize against the potential risk that a participant will default on payment obligations arising from negative capacity payments associated with a CSO after non-performance or underperformance of its resources during a Capacity Scarcity Condition. As a result, that portion of the formula uses historical performance data relative to the amount of system-wide reserves needed to avoid a Capacity Scarcity Condition.").

As addressed in the Balancing Ratio Cap Compliance Filing, the ISO is proposing to modify the definition of ABR as follows (red text reflects new language):

> ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. *For the purpose of calculating the ABR, all Capacity Balancing Ratios, including Capacity Balancing Ratios for Capacity Scarcity Conditions that occurred in past Capacity Commitment Periods or in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, shall be calculated utilizing the Capacity Balancing Ratio formula that is currently effective, as described in Section III.13.7.2.3 or Section III.15.8.2.3 of Market Rule 1.*[91] Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60.[92]

This proposed change is relevant to both the Balancing Ratio Cap Compliance Filing proposal and the instant Proposal because each proposal includes a change to the calculation of the Balancing Ratio. The ISO restates the proposed revision in the instant Proposal because the proposed revision applies independently to the present System-Backed Export Charge proposal.

3. Additional Conforming Change

In addition to the FAP changes described above, the ISO's Proposal adds a reference to System-Backed Export transactions to FAP Section III.A., which specifies that a Market Participant's Financial Assurance Obligations equal the sum of the various components or "buckets" of financial assurance, such as Hourly Requirements, Daily FCM Requirements, Non-Hourly Requirements, and FCM Financial Assurance Requirements.[93] In this case, because SBE Financial Assurance will be captured in a participant's FCM Financial Assurance Requirements, the Proposal includes a

[91] The new language in red text is identical to the proposed revision to the ABR submitted in the Balancing Ratio Cap Compliance Filing.

[92] Revised Tariff, FAP § VII.A.1.

[93] *Id.* FAP § III.A.(iv).

conforming change in Section III.A to ensure that SBE Financial Assurance is not included in the definition of Non-Hourly Requirements.[94]

G. Billing Policy Change

The ISO's Proposal also includes a conforming change to the Billing Policy. Specifically, the proposed revision to the Billing Policy adds a reference to System-Backed Export Charges to Section 2.4, which identifies the line items included in statements issued by the ISO, in subsection (e) "Monthly Forward Capacity Market Charges and Payments."[95]

VI. REQUESTED EFFECTIVE DATE

The ISO respectfully requests that the Commission accept the Tariff revisions proposed herein, as filed, without suspension or hearing, to be effective on October 1, 2026, which is 62 days from the date of this filing.

VII. STAKEHOLDER ENGAGEMENT AND THE NEPOOL PARTICIPANT PROCESSES

Over the course of three meetings, starting in March 2026, the ISO discussed its System-Backed Export Charge proposal with regional stakeholders. At its May 12–14, 2026 meeting, based on a show of hands vote, the NEPOOL Markets Committee voted unanimously, with abstentions noted, to recommend a motion that the NEPOOL Participants Committee support the Proposal.[96]

Over the course of three meetings of the NEPOOL Budget and Finance Subcommittee,[97] starting in April 2026, the ISO discussed the proposed revisions to the FAP and to the Billing Policy related to the System-Backed Export Charge proposal. No subcommittee member present at the meetings objected to or expressed concern with the revisions.

At its June 16–18, 2026 meeting, the NEPOOL Participants Committee considered the Markets Committee-recommended Tariff revisions to implement the ISO's System-Backed Export Charge proposal. Based on a show of hands vote, the

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[94] *Id*. FAP § III.A.(iii).

[95] Revised Tariff, Billing Policy § 2.4(e).

[96] There were eleven abstentions, one in each of the Alternative Resource, End User, and Generation Sectors and eight in the Supplier Sector.

[97] The Budget and Finance Subcommittee is a non-voting subcommittee that provides input and advice to the ISO and the NEPOOL Participants Committee concerning changes to Financial Assurance Policy, among other things.

Participants Committee supported the Proposal, with one opposition, and abstentions noted.[98]

VIII. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates. However, the proposed Tariff changes do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the Filing Parties request waiver of Section 35.13 of the Commission's regulations.[99] Notwithstanding its request for waiver, the Filing Parties submit the following additional information in substantial compliance with relevant provisions of Section 35.13 of the Commission's regulations:

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

- This transmittal letter;
- The Testimony of Dr. Enrico De Magistris, sponsored solely by the ISO;
- Redlined Tariff sections effective October 1, 2026;
- Clean Tariff sections effective October 1, 2026; and
- List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont to which a copy of this filing has been sent.

35.13(b)(2) – As set forth above, the ISO requests that the Tariff revisions filed herewith become effective on October 1, 2026.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at https://www.iso-ne.com/participate/participant-asset-listings/directory?id=1&type=committee. A copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, the New England Conference of Public Utility Commissioners, Inc., and to

[98] MAG Energy Solutions, Inc. (Supplier Sector) opposed. The following members abstained: BP Energy Company (Supplier Sector); Cross-Sound Cable Company, LLC (Supplier Sector); DTE Energy Trading, Inc. (Supplier Sector); FirstLight Power Management LLC (Generation Sector); Galt Power Inc. (Supplier Sector); Mr. Jon Lamson (End User Sector); Long Island Power Authority (Supplier Sector); and Mercuria Energy America, LLC (Supplier Sector).

[99] 18 C.F.R. § 35.13.

the New England States Committee on Electricity. Their names and addresses are shown in the attached listing. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified in the listing to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

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

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

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

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

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

35.13(c)(1) – The market rule changes proposed herein do not modify a traditional "rate," and the statement required under this Commission regulation is not applicable to the instant filing.

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

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

IX. CONCLUSION

For the reasons set forth above, the Filing Parties respectfully request that the Commission accept the Tariff revisions filed herein without condition or delay to become effective on October 1, 2026, as described above.

Respectfully submitted,

ISO NEW ENGLAND INC.

By: /s/ *Kelly Caiazzo*

Kelly Caiazzo, Esq.
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
Tel: (413) 540-4610
Email: kcaiazzo@iso-ne.com

NEW ENGLAND POWER POOL PARTICIPANTS COMMITTEE

By: */s/ Rosendo Garza, Jr.*

Rosendo Garza, Jr., Esq.
Sebastian M. Lombardi, Esq.
Day Pitney LLP
Goodwin Square
225 Asylum Street
Hartford, CT 06103
Tel: (860) 275-0660
Fax: (860) 881-2493
E-mail: rgarza@daypitney.com
slombardi@daypitney.com

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER26-_____-000**
NEPOOL Participants Committee	**)**	

TESTIMONY OF
DR. ENRICO DE MAGISTRIS
ON BEHALF OF ISO NEW ENGLAND INC.

I. WITNESS IDENTIFICATION

Q: Please state your name, position, and business address.

A: My name is Enrico De Magistris. I am an Economist in the Market Development department at ISO New England Inc. (the "ISO" or "ISO-NE"). My business address is One Sullivan Road, Holyoke, MA 01040.

Q: Please describe your professional experience and qualifications.

A: My primary responsibilities involve identifying and designing potential market improvements for New England's wholesale electricity markets. Since joining the ISO in April 2025, I have worked primarily on reforms to the Pay for

Performance ("PFP") aspects of the Capacity Market,[1, 2] such as the current proposal on System-Backed Exports ("SBE") and the capping at 1.0 of the Capacity Balancing Ratio ("Balancing Ratio" or "BR").[3]

Prior to joining the ISO, I was an Associate at Cornerstone Research, an economic consulting firm. I received a PhD in Economics from Boston University in 2022.

II. PURPOSE AND ORGANIZATION OF TESTIMONY

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to explain the ISO's System-Backed Export Charge revisions to the Pay for Performance market rules, which include a proposal to charge net System-Backed Exports the Capacity Performance Payment Rate during Capacity Scarcity Conditions, a proposal regarding the allocation of collected System-Backed Export Charges, and a proposal to remove

[1] Capitalized terms used in this testimony but not otherwise defined herein shall have the meaning set forth in the ISO New England Transmission, Markets and Services Tariff (the "Tariff"), the Second Restated NEPOOL Agreement, the Participants Agreement, and in the proposed Tariff revisions submitted as part of this filing ("Revised Tariff").

[2] In March 2026, the Federal Energy Regulatory Commission accepted ISO-NE's Capacity Auction Reforms – Prompt Deactivation, which replaced the Forward Capacity Market with the Annual Capacity Market. *See ISO New England Inc.*, 194 FERC ¶ 61,249, at P 1 (2026). The discussion of the Pay for Performance market rules herein applies to both the Forward Capacity Market and the Annual Capacity Market unless otherwise noted. Tariff Section III.13 sets forth market rules addressing the Forward Capacity Market. Tariff 1 Section III.15 sets forth market rules addressing the Annual Capacity Market.

[3] The ISO has filed with the Federal Energy Regulatory Commission ("Commission") a currently pending compliance proposal to cap the Capacity Balancing Ratio at 1.0. *See ISO New England Inc.*, Docket No. EL25-106-000 Compliance Filing, Docket No. ER26-3213-000 ("Balancing Ratio Cap Compliance Filing") (filed July 21, 2026).

System-Backed Exports from the calculation of the Balancing Ratio.

Q: How is your testimony organized?

A: Section III provides background on the current Pay for Performance market design. Section IV discusses the components of the System-Backed Export Charge proposal and the ISO's rationale for the proposal.

III. PAY FOR PERFORMANCE MARKET RULES

Q: Please provide an overview of ISO New England's Pay for Performance market rules.

A: The ISO's Capacity Market is a two-settlement market in which resources may, through a capacity auction, acquire a Capacity Supply Obligation ("CSO") in exchange for monthly Capacity Base Payments. Resources that acquire a CSO also acquire an obligation to provide energy and/or reserves to the ISO New England system during Capacity Scarcity Conditions ("CSC") in proportion to their share-of-system obligation, the product of their CSO and the Capacity Balancing Ratio.

Negative deviations from a resource's share-of-system obligation during a CSC are assessed a monetary charge, and positive deviations are paid monetary payments. These performance charges and payments, collectively called Capacity Performance Payments, constitute the second part of the two-settlement market

system mentioned above, and work as a transfer from resources performing below their share-of-system obligation to resources performing above it.[4]

Q: What is the primary purpose of the Pay for Performance design?

A: The ISO first proposed the Pay for Performance mechanism in 2014 to address two major issues identified with the capacity market at that time: first, that resources had inefficiently low incentives to perform during periods of heightened system stress; and second, that the capacity market was more likely to award capacity positions to less reliable resources that had lower capacity costs.

The main innovation of the PFP design is that performance during scarcity conditions results in additional payments or charges. Thus, the PFP rules incentivize better performance during times of scarcity. During a Capacity Scarcity Condition, in which the system is "tight" and its reserves needs are not met, the Pay for Performance rules provide monetary payments to resources that perform more than their obligation and charges to resources that perform less than their obligation. The PFP rules also produce more efficient capacity market

[4] The background and purpose of the Pay for Performance design are discussed in additional detail in the ISO's currently pending filing to change the Capacity Performance Payment Rate. *See ISO New England Inc.*, Revisions to Change the Capacity Performance Rate to $3,500 per MWh, Docket No. ER26-3047-000 ("Performance Payment Rate Revision Filing"), Testimony of Dr. Christopher Geissler and Dr. John Withers ("PPR Geissler and Withers Testimony"), at 5–14 (filed June 30, 2026). *See also ISO New England Inc.*, Filing of Performance Incentives Market Rule Changes., Docket No. ER14-1050-000, Testimony of Dr. Matthew White ("PFP White Testimony"), at 58–59 (filed January 17, 2014).

outcomes by adding a cost for poor performance that impacts the set of resources that receive capacity obligations.[5]

Q: How does the market design incentivize resource performance during scarcity conditions?

A: During a CSC, the PFP design incents resources to provide energy and/or reserves to the New England Control Area by providing a scarcity price adder, on top of the energy market's scarcity pricing rules, for resource overperformance and charging for resource underperformance. Specifically, each resource may receive a (positive or negative) Capacity Performance Payment that reflects their performance relative to their share-of-system obligation during the CSC. A resource with a CSO is incented to provide energy and/or reserves to avoid charges for underperformance and receive payments for performing above the resource's share-of-system obligation. A resource without a CSO is incented to provide energy and/or reserves during a CSC because such resources are also eligible to receive Capacity Performance Payments.

Q: How are Capacity Performance Payments calculated?

A: For each resource, and for each five-minute interval in which a CSC exists in the Capacity Zone in which the resource is located, the ISO calculates the resource's Capacity Performance Score, the difference between the total amount of energy and reserves the resource provided to the New England Control Area (called

[5] *See* PPR Geissler and Withers Testimony at 7–14; *see* PFP White Testimony, at 14–19.

"Actual Capacity Provided" or "ACP") and the resource's share-of-system obligation, the product of the resource's CSO and the Capacity Balancing Ratio, the ratio of system load and reserve requirements during the CSC relative to the total CSO in New England.[6] As such, the Capacity Performance Score may be positive, zero, or negative, and reflects the resource's contribution to system reliability in the New England Control Area. To calculate Capacity Performance Payments, the ISO multiplies the resource's Capacity Performance Score by the Capacity Performance Payment Rate.

Q: How does the ISO calculate the Actual Capacity Provided during a Capacity Scarcity Condition?

A: As mentioned above, the Actual Capacity Provided measures, in MW, the energy and reserves that a resource provides to the New England Control Area during a CSC. For each resource type, the Tariff prescribes how to calculate the Actual Capacity Provided by a resource belonging to that resource type, regardless of whether the resource has acquired a CSO. The Tariff sets a floor for the calculation of Actual Capacity Provided at 0 MW.[7] For the purpose of this testimony, I will only discuss the calculation of Actual Capacity Provided of the

[6] Stated in an equation, a resource's Capacity Performance Score = ACP – (CSO × BR). *See, infra*, n.9 and n.10 (regarding the calculation of the Balancing Ratio for CSCs that are the result of a violation of the Zonal Reserve Requirement).

[7] Tariff §§ III.13.7.2.2, III.15.8.2.2 ("no resource shall have an Actual Capacity Provided that is less than zero").

two resource types relevant to the ISO's System-Backed Export Charge proposal, generator resources and import resources.

For generator resources, for each five-minute interval in which a Capacity Scarcity Condition exists, Actual Capacity Provided is the sum of the resource's energy output during the interval and its Reserve Quantity for Settlement. If the resource is associated with one or more External Transaction sales, the resource will have its Actual Capacity Provided reduced by the hourly integrated delivered MW from all External Transaction sales, floored at 0.

For import resources, for each five-minute interval during which a Capacity Scarcity Condition exists, Actual Capacity Provided is the net energy delivered, that is, the sum of the External Transactions (sales and purchases) submitted by a Market Participant, floored at 0.[8] As I will discuss shortly, the floor at 0 of the Actual Capacity Provided creates a market inefficiency in the PFP treatment of external transactions that the ISO seeks to correct.

Q: How does the ISO calculate the Capacity Balancing Ratio?

A: During a CSC, the Capacity Balancing Ratio is the ratio between the system's energy needs, i.e. load and reserve requirements, and the total amount of Capacity Supply Obligation in the system.[9] For system-wide CSCs, the load in the

[8] Where the ACP for import resources is based on the net energy delivered from all External Transaction sales and purchases, it is ultimately calculated at the Market Participant level.

[9] For a Capacity Scarcity Condition that is a result of a violation of the Zonal Reserve Requirement, the denominator of the BR is calculated as the total amount of CSO in the Capacity Zone affected by the CSC.

numerator of the BR is calculated as the total amount of Actual Capacity Provided (less the total amount of reserve designations) across all resources in the system.[10]

Q: How are Capacity Performance Payments allocated?

A: As I mentioned above, Capacity Performance Payments are the product of the Performance Payment Rate and the resource's Capacity Performance Score.[11] A resource's Capacity Performance Payment can be positive or negative, capturing whether the resource has performed above or below its obligation. The negative payments together constitute a pool of monies that are used to pay overperforming resources, carrying out the financial transfers of Pay for Performance.

Q: Are there any limits on a resource's financial losses under the Pay for Performance design?

A: Yes. The PFP rules include a stop-loss mechanism, which acts as a mutual insurance system for resources with a CSO. Through the stop-loss mechanism, a CSO resource's charges from negative performance are stopped when it reaches a certain stop-loss limit, and the rest of the CSO resources, which have not reached the stop-loss limit, are allocated the deficiency that results from the uncollected funds. There is a monthly stop-loss limit, limiting the amount of net financial

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[10] For a Capacity Scarcity Condition that is a result of a violation of the Zonal Reserve Requirement, the load in the numerator of the BR is calculated as the total amount of Actual Capacity Provided (less the total amount of reserve designations) from all resources in the Capacity Zone.

[11] The Performance Payment Rate is an administratively-determined rate that is currently set at $9,337 per MWh. Tariff §§ III.13.7.2.5, III.15.8.2.5. The ISO has filed with the Commission a proposal to change the Performance Payment Rate to $3,500 per MWh. *See* Performance Payment Rate Revision Filing.

losses from PFP charges that a resource can incur across all CSCs in a single month, and an annual stop-loss limit, limiting net financial losses from charges incurred over a Capacity Performance Period.

Q: Are exports charged the Performance Payment Rate under the current rules?

A: Currently, exports of energy out of the New England Control Area during a CSC can reduce a resource's Actual Capacity Provided, and, thus, in the case of a CSO resource, can lead to a negative Capacity Performance Score and negative Capacity Performance Payment when exports reduce a resource's contribution of energy and reserves below its share-of-system obligation.

For example, if a Market Participant had a CSO of 100 MW, and, for each interval of a one-hour CSC, External Transaction purchases (imports) of 100 MW, and External Transaction sales (exports) of 10 MW, the resource's Actual Capacity Provided would be 90 MW, resulting (assuming, for simplicity, no reserves provided and a Balancing Ratio of 1.0) in a Capacity Performance Score of -10 MW (-10 MW = 90 MW ACP – [100 MW CSO × 1 BR]), and a Capacity Performance Payment of $-93,370 (-10 × $9,337).[12]

[12] Tariff §§ III.13.7.2.5, III.15.8.2.5.

Thus, resources with a CSO can be charged negative Capacity Performance Payments when exports contribute to a resource underperforming its share of system obligation.

However, since the Actual Capacity Provided floor is set at 0, exports that would exceed a (CSO or non-CSO) resource's provision of energy and reserves to the New England system do not currently incur a PFP charge.

To illustrate, if, in a modified version of the previous example, the Market Participant had a CSO of 100 MW and External Transaction purchases (imports) of 100 MW but instead had External Transaction sales (exports) of 110 MW, the resource's Actual Capacity Provided would be 0 MW (not -10 MW, due to the 0 MW floor), resulting in a Capacity Performance Score of -100 MW (-100 MW = 0 MW ACP – [100 MW CSO × 1 BR]), and a Capacity Performance Payment of $-933,700 (-100 × $9,337), reflecting the 100 MW CSO that was not met. However, the additional 10 MW of net exports would not incur a PFP charge.

Additionally, to illustrate another case, if a Market Participant had no CSO, no External Transaction purchases (imports), and External Transaction sales (exports) of 100 MW, the resource's Actual Capacity Provided would be 0 MW (not -100 MW, due to the 0 MW floor), resulting in a Capacity Performance Score of 0 MW (0 MW = 0 MW ACP – [0 MW CSO × 1 BR]), and no Capacity Performance Payment or charge.

Q: Is the ISO concerned about the treatment of exports under the current Pay for Performance rules?

Yes. As illustrated in the examples above, the participants in the latter two examples do not incur negative Capacity Performance Payments for the exports that exceed their contribution of energy and reserves to the system, even though those transactions export energy out of the New England Control Area during times of greatest system need.

Q: How does this impact the incentives for exporting energy out of the ISO-NE system during scarcity conditions?

A: The absence of charges for exports that exceed a resource's contribution of energy and reserves to the system creates asymmetries in the treatment of exports under the PFP design. First, exports that do *not* exceed a resource's contribution of energy and reserves to the system can lead to a reduction of the resource's ACP and can result in a PFP charge, while exports that *do* exceed a resource's contribution of energy and reserves to the system cannot reduce the resource's ACP below 0 and will not result in a PFP charge. Therefore, exports receive a different treatment during CSCs based on the resource's ACP, even though no principled economic reason underlies this difference.

Second, because exports that exceed a resource's contribution of energy and reserves to the system will not result in PFP charges, incentives for imports

(which receive PFP credits) and incentives for exports (which do not always receive PFP charges) during CSCs are not aligned.[13]

These inconsistencies produce an inefficiency in the form of a money-for-nothing problem. As I discuss below, two Market Participants can jointly exploit this inefficiency in order to receive Capacity Performance Payments while not actually contributing to system reliability.

IV. SYSTEM-BACKED EXPORT CHARGE PROPOSAL

A. OVERVIEW AND RATIONALE

Q: Please describe the System-Backed Export Charge proposal at a high level.

A: The ISO proposes that, during a CSC, exports that exceed the energy and reserves that a resource provides to the New England Control Area be charged the Performance Payment Rate. These exports are effectively backed by the whole New England system and therefore are subject to the proposed System-Backed Export Charge.[14] Exports that do not exceed the contribution of energy and

[13] The ISO-NE Internal Market Monitor states that the current PFP "structure creates unequal incentives for imports and exports during scarcity events, crediting imports at the PfP rate but not applying the same charges to all exports." ISO New England Internal Market Monitor, *2024 Annual Markets Report*, May 23, 2025, at 22–23, *available at* https://www.iso-ne.com/static-assets/documents/100023/2024-annual-markets-report.pdf. The ISO-NE External Market Monitor states that the current PFP rules create "inefficient incentives for external transaction scheduling during shortage conditions." *See* Potomac Economics, *2025 Assessment of the ISO New England Electricity Markets*, June 2026, at 64–65, *available at* https://www.iso-ne.com/static-assets/documents/100037/iso-ne-2025-emm-report-final.pdf.

[14] As explained below, the proposed Tariff revisions define the scope of System-Backed Exports for External Transactions associated with a generator and those not associated with a generator, and set forth the formulas for calculating the net System Backed Export value, the portion of a System-Backed Export that is subject to the System-Backed Export Charge.

reserves to the New England Control Area (i.e., exports that are backed by generation or offset by imports) are not charged under the proposal.

Q: Why is the ISO proposing to charge net System-Backed Exports?

A: The ISO is proposing to charge net System-Backed Exports to address asymmetries in the current design. First, the proposal is designed to ensure that all exports receive the same treatment during a Capacity Scarcity Condition. As noted above, exports that do *not* exceed a resource's contribution in terms of energy and reserves provided to the system are already accounted for in the PFP design because they reduce the resource's ACP, and therefore its Capacity Performance Payment. In contrast, because the ACP floor is set at 0, exports that *do* exceed the resource's energy and reserves are not accounted for. There is no economic rationale for this asymmetry in treatment, and the new System-Backed Export Charge eliminates it.

Additionally, imposing a charge on System-Backed Exports that exceed the energy and reserves that a resource contributes to the system aligns the treatment of such exports with imports, and with the Pay for Performance objective of incentivizing performance during scarcity conditions. Correspondingly, the new charge eliminates the money-for-nothing problem created by setting the Actual Capacity Provided floor at 0, as I detail below.

Q: Can you please explain the money-for-nothing problem that you are referring to?

A: Yes. Two Market Participants could coordinate their external transactions so that one would export an amount of energy out of the New England system, and the other would import the same amount of energy into New England. These two transactions would result in no net energy flowing and would not contribute to system reliability, yet, due to the 0 MW ACP floor, the importing Market Participant would receive PFP credits that it could share with the exporting participant, thus constituting a money-for-nothing problem.

To see the point more concretely, imagine that Market Participants A and B each do not have Capacity Supply Obligations. Suppose that A schedules 1 MW of exports and 0 MW of imports, while B schedules 0 MW of exports and 1 MW of imports during a CSC. Under current rules, A's exports are not charged the Performance Payment Rate, while B's imports are accounted for with an Actual Capacity Provided of 1 MW, and thus receive the Performance Payment Rate. Overall, Market Participant A's and Market Participant B's imports and exports result in no flow of energy (at the system level, they net out) but do result in a Capacity Performance Payment that A and B can share through an out-of-market agreement.

To the best of ISO-NE's knowledge, no Market Participant has engaged in this behavior. The current proposal prevents Market Participants from exploiting this inefficiency in the future by imposing the same charge on A's export as B's import and eliminating the net Capacity Performance Payment for their transactions.

B. DEFINITION OF SYSTEM-BACKED EXPORTS AND CALCULATION OF SYSTEM-BACKED EXPORT CHARGES

Q: Please provide a brief explanation of how External Transactions are submitted and scheduled in ISO-NE.

A: At a very high level, Market Participants can submit an External Transaction to ISO New England, specifying the flow (into New England or out of New England), the external node, and price. Submissions for External Transactions also indicate whether the transaction is associated with a generator. External Transactions can be submitted in the Day-Ahead and Real-Time energy markets and are scheduled according to the provisions contained in the Tariff at Sections III.1.10.7 and III.1.10.7.A.

Q: Please explain how System-Backed Exports are defined in the ISO's proposal.

A: The proposed definition of System-Backed Exports addresses two types of External Transaction sales, those associated with a generator and those not associated with a generator. At a high level, System-Backed Exports are External Transaction sales that are either not associated with a generator, or associated with a generator but exceeding the energy and reserves the generator provides. Specifically, Section III.13.7.2.A.1 of the Revised Tariff states:

> A System-Backed Export is an External Transaction submitted in accordance with Section III.1.10.7 or Section III.1.10.7.A to export internal energy out of the New England Control Area by a Market Participant in the Real-Time Energy Market: (1) that is not associated with a generator; or (2) for External Transactions associated with a generator, for which the megawatt amount of the External Transaction sale(s)

> associated with the generator is greater than the sum of the resource's energy output plus the resource's Reserve Quantity For Settlement.[15]

While this definition establishes the scope of System-Backed Exports, as I discuss below, under the ISO's proposal, only the portion of System-Backed Exports that exceed the contribution of energy and reserves provided, or the net System-Backed Export value, are charged the Performance Payment Rate during a CSC.

Q: Please explain how System-Backed Export Charges are calculated for External Transactions associated with a generator and External Transactions not associated with a generator.

A: Under the proposal, the ISO will calculate a System-Backed Export Charge for each five-minute interval in which a Capacity Scarcity Condition exists for External Transactions associated with a generator and External Transactions not associated with a generator. For both types of System-Backed Exports, the System-Backed Export Charge equals the product of the net System-Backed Export value, calculated in accordance with the applicable formula described below, and the Capacity Performance Payment Rate. Section III.13.7.2.A.2 of the Revised Tariff states:

> For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a System-Backed Export Charge: (1) for External Transactions associated with a generator, for each resource that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval; and (2) for External Transactions not associated with a generator, for each Market Participant that submitted an External Transaction sale in the Real-Time Energy

[15] *See also* Revised Tariff § III.15.8.2.A.1. The ISO's proposal includes parallel changes to Section III.13 and Section III.15 of the Tariff.

> Market corresponding with the five-minute interval. For each five-minute interval, the System-Backed Export Charge shall be equal to the net System-Backed Export value, calculated in accordance with the formulas set forth below, multiplied by the Capacity Performance Payment Rate, as defined in Section III.13.7.2.5.[16]

Q: Please explain how net System-Backed Export values are calculated for External Transaction sales not associated with a generator under the ISO's proposal.

A: As explained above, in calculating the Actual Capacity Provided for importing resources, the ISO nets the External Transaction purchases (imports) with the External Transaction sales (exports), up to the quantity where exports exceed imports. Under the proposal, if exports do exceed imports, the excess portion constitutes the net System-Backed Export value that is subject to the new charge. Section III.13.7.2.A.2 of the Revised Tariff explains this calculation in the following formula:

> For External Transactions not associated with a generator,
>
> net System-Backed Export value = the lesser of (the hourly integrated delivered MW for the External Transaction purchase(s) of the Market Participant – the hourly integrated delivered MW for the External Transaction sale(s) of the Market Participant) or 0.[17]

The net System-Backed Export value can be negative (when exports exceed imports) or 0 (when imports and exports are equal or imports exceed exports).

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[16] *See also* Revised Tariff § III.15.8.2.A.2.

[17] *See also* III.15.8.2.A.2. Consistent with the calculation of ACP for import resources, net System-Backed Export values for System-Backed Exports not associated with a generator are based on the net energy delivered and are calculated at the Market Participant level.

This value is multiplied by the Capacity Performance Payment Rate to produce the System-Backed Export Charge.

Q: Please explain how net System-Backed Export values are calculated for External Transaction sales associated with a generator under the ISO's proposal.

A: As explained above, exports associated with a generator reduce the generator's Actual Capacity Provided, but not below 0. Under the proposal, if an export of energy exceeds the energy and reserves provided by the generator, then the excess portion constitutes the net System-Backed Export value that is subject to the new charge. Section III.13.7.2.A.2 of the Revised Tariff explains this calculation in the following formula:

> For External Transactions associated with a generator,
>
> net System-Backed Export value = the lesser of (the energy output of the generator in the interval + the Reserve Quantity for Settlement of the generator in the interval – the hourly integrated delivered MW for the External Transaction sale(s) associated with the generator) or 0.[18]

The net System-Backed Export value can be negative (when exports exceed the energy and reserves provided by the generator) or 0 (when exports are equal to the energy and reserves provided by the generator or when the energy and reserves provided by the generator exceed exports). This value is multiplied by the

[18] *See also* Revised Tariff § III.15.8.2.A.2.

Capacity Performance Payment Rate to produce the System-Backed Export Charge.[19]

Q: Can you provide an example of a scenario in which an External Transaction sale associated with a generator would be a System-Backed Export subject to a charge?

A: Yes, for example, a generator may provide less energy and reserves to the system than its scheduled External Transaction sales because of physical factors or because some of its components trip offline. To see the point more clearly, consider the following example.

A participant submits an External Transaction sale of 10 MW associated with Generator X for the hour ending at 17:00. There is a Capacity Scarcity Condition during the whole hour. Generator X is dispatched to its maximum capability and provides 12 MWh of energy and reserves to the system, until it experiences an internal plant equipment failure (or it "partially trips offline") at 16:30, and the generator provides only 7 MW of energy and reserves thereafter.

Thus, Generator X's Actual Capacity Provided, equal to the energy and reserves it provided to the system minus the External Transaction sales, and floored at 0, equals 2 MW (12 MW of energy and reserves minus 10 MW of exports) for the five-minute intervals between 16:00 and 16:30, and equals 0 MW (7 MW of

[19] Because the net System-Backed Export value can be 0 or negative, multiplying the net System-Backed Export value by the Capacity Performance Payment Rate may result in a charge (when the value is negative) or no charge (when the value is 0), but not a payment.

energy and reserves minus 10 MW of exports, floored at 0) for the intervals between 16:30 and 17:00.

On the other hand, Generator X's net System-Backed Export values would be 0 MW (the lesser of (12 MW of energy and reserves minus 10 MW exports) and 0) for the intervals between 16:00 and 16:30, where the generator provides the system with enough energy and reserves to cover its exports, and would equal -3 MW (the lesser of (7 MW of energy and reserves minus 10 MW exports) and 0) for the remaining intervals where part of the generator tripped offline. For these intervals, Generator X would be subject to a System-Backed Export Charge for the 3 MW of exports that exceeded its contribution of energy and reserves.

Q: Does the calculation of System-Backed Export Charges align with the calculation of Capacity Performance Payments?

A: Yes. Both System-Backed Export Charges and Capacity Performance Payments are calculated for each five-minute interval in which a Capacity Scarcity Condition exists. Furthermore, both net System-Backed Exports and negative Capacity Performance Scores are charged the same rate, the Capacity Performance Payment Rate.

Q: Is the ISO proposing any changes to the calculation of Actual Capacity Provided during a Capacity Scarcity Condition?

A: The ISO is not proposing any changes to the calculation of Actual Capacity Provided. The Actual Capacity Provided floor of 0 MW is maintained.

Q: Can a resource incur both a capacity performance charge and a System-Backed Export charge?

A: Yes. To see this concretely, consider again the previous example in which Generator X provides 12 MW in energy and reserves and has submitted an export of 10 MW during a Capacity Scarcity Condition, but partially trips offline midway through the CSC, providing 7 MW in energy and reserves thereafter. Suppose that Generator X has a share-of-system obligation of 1 MW throughout the CSC. As I discussed above, the Actual Capacity Provided by Generator X would be 2 MW for the five-minute intervals between 16:00 and 16:30, leading to a positive Capacity Performance Score of 1 MW.

The Actual Capacity Provided by Generator X would be 0 MW for the five-minute intervals between 16:30 and 17:00, leading to a negative Capacity Performance Score of -1 MW. Thus, the ISO would calculate a positive Capacity Performance Payment for Generator X for the first six five-minute intervals and a negative Capacity Performance Payment for the second six five-minute intervals. As I discussed, the ISO would also calculate a System-Backed Export Charge for Generator X during the second six 5-minute intervals.

Q: Can a resource that does not have a Capacity Supply Obligation incur a System-Backed Export Charge?

A: Yes. Resources that export energy out of the system during a Capacity Scarcity Condition without backing these exports with corresponding generation or offsetting them with imports are effectively contributing to the Capacity Scarcity

Condition—they are purchasing internal New England System energy and exporting that energy outside the system during the Capacity Scarcity Condition, thus reducing the energy available to the New England System to address or help prevent the scarcity. As such, they impose a cost on the New England System that needs to be appropriately priced. Charging System-Backed Exports the Performance Payment Rate, and adding the levied monies to the total of Capacity Performance Payments, also helps ensure that the resources that overperform during CSCs are appropriately compensated by all resources that are contributing to the scarcity by exporting energy or underperforming their share-of-system obligation.

Q: Would exports scheduled for emergency assistance programs be subject to a System-Backed Export Charge?

A: No. Exports scheduled for emergency assistance programs are excluded from the definition of System-Backed Exports. Specifically, System-Backed Exports are External Transactions submitted by a Market Participant in accordance with Section III.10.7 or Section III.1.10.7.A of the Tariff, whereas exports scheduled for emergency assistance programs are directly managed by the ISO's control room.

C. ALLOCATION OF CAPACITY PERFORMANCE PAYMENTS AND SYSTEM-BACKED EXPORT CHARGES

Q: Please explain how the ISO proposes to allocate System-Backed Export Charges.

A: I mentioned before that resources which, during a Capacity Scarcity Condition, performed below their share-of-system obligation are charged a negative Capacity Performance Payment, and that those negative Capacity Performance Payments are used to pay resources that perform above their share-of-system obligation, i.e., resources with positive Capacity Performance Payments. The new System-Backed Export Charges will be added to the negative Capacity Performance Payments and form a single pool of monies used to pay resources performing above their obligations.[20]

Q: Why is the ISO proposing to pool negative Capacity Performance Payments and System-Backed Export Charges and allocate those funds to overperforming resources?

A: As I mentioned before, net System-Backed Exports impose a cost on the reliability of the system during a Capacity Scarcity Condition. As such, System-Backed Export Charges should be used to incent performance during times of greatest system need, together with other monies levied for the same scope, i.e., negative Capacity Performance Payments.

Q: Does this proposed allocation impact the Tariff revisions that the ISO has proposed in the Balancing Ratio Cap Compliance Filing regarding the allocation of Capacity Performance Payments?

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[20] The allocation of Capacity Performance Payments is discussed in additional detail in the ISO's Balancing Ratio Cap Compliance Filing. *See* Balancing Ratio Cap Compliance Filing Transmittal Letter, at 7–9.

A: While System-Backed Export Charges will be added to negative Capacity Performance Payments to form a single pool of monies, the ISO is not proposing any other changes to the allocation of deficient or excess Capacity Performance Payments.

Consistent with the allocation proposed in the Balancing Ratio Cap Compliance Filing, deficient (Capacity Performance Payments and System-Backed Export Charges) will be allocated to overperforming resources on a pro-rata, by positive Capacity Performance Score, basis, and excess (Capacity Performance Payments and System-Backed Export Charges) will be allocated to capacity resources on a pro-rata, by CSO MW, basis.

In terms of practical impact, the additional monies collected through the System-Backed Export Charge can only increase the total collected funds, and therefore any such charges would decrease a deficiency or increase an excess of funds.

Q: Is the ISO proposing any changes to the stop-loss mechanism?

A: No. Specifically, System-Backed Export Charges will not contribute to the accrual of negative Capacity Performance Payments used in the calculation of the monthly or annual stop-loss limit. The stop loss mechanism acts as a mutual insurance mechanism among CSO resources, limiting a capacity resource's net financial losses on a monthly and annual basis. CSO resources benefit from, and pay for, this mutual insurance mechanism.

Thus, only capacity that is subject to a CSO can benefit from the stop-loss mechanism. As a result, since the energy exported via a net System-Backed Export is expressly not energy that is subject to a CSO, it is not (and should not be) subject to the stop-loss mechanism. Including System-Backed Export Charges in the charges that can be stopped would be contrary to the mutual insurance pool rationale for the stop-loss mechanism.

D. REMOVAL OF SYSTEM-BACKED EXPORTS FROM THE CAPACITY BALANCING RATIO

Q: Please explain the proposed change to the calculation of the Capacity Balancing Ratio.

A: The Capacity Balancing Ratio is the ratio between load plus reserve requirements and the total of Capacity Supply Obligations, where, for system-wide events, the load component of the numerator equals the total amount of Actual Capacity Provided in the system, net of reserve designations. The ISO proposes to subtract the total net System-Backed Export values from the load component.[21]

Q: Why is the ISO proposing this change?

A: Removing net System-Backed Export values from the Capacity Balancing Ratio would treat all External Transactions transferring energy out of the New England Control Area in the same way. Under current rules, External Transaction sales

[21] The ISO proposes to subtract the total net System-Backed Export values from the load component of the Capacity Balancing Ratio for each type of reserve deficiency that results in a Capacity Scarcity Condition: a violation of the Minimum Total Reserve Requirement, a violation of the Ten-Minute Reserves Requirement, or a violation of the Zonal Reserve Requirement.

that do not exceed a resource's contribution of energy and reserves to the system reduce the resource's Actual Capacity Provided and thus, mechanically, the Capacity Balancing Ratio. However, because External Transaction sales that exceed a resource's contribution of energy and reserves to the system do not reduce a resource's Actual Capacity Provided, net System-Backed Exports are implicitly included in the Capacity Balancing Ratio. The ISO's proposed change addresses this asymmetry. It also simplifies the settlement of CSO resources following one or more Capacity Scarcity Conditions in a given month.

Q: Does this proposal to remove net System-Backed Export values from the calculation of the Capacity Balancing Ratio impact the Tariff revisions that the ISO has proposed in the Balancing Ratio Cap Compliance Filing?

A: No. The proposal to remove System-Backed Exports from the numerator of the Capacity Balancing Ratio does not modify the proposal to cap the Capacity Balancing Ratio at 1.0. However, removing net SBE values from the numerator of the Capacity Balancing Ratio mechanically makes it less likely for the Balancing Ratio to hit the 1.0 cap.

V. CONCLUSION

Q: Does this conclude your testimony?

A: Yes.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on July 31, 2026.

Enrico De Magistris

Enrico De Magistris, ISO New England, Market Development

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or

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

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

I.2.2. Definitions:

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

Above-Threshold Offer Segment is the total MW quantity of a Capacity Offer that is priced above the Capacity Offer Price Threshold, whether such MW quantity is delimited by only one price-quantity pair or multiple price-quantity pairs submitted as part of the Capacity Offer pursuant to Section III.15.4.1.

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward or Annual Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 or Section III.15 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 or Section III.15.8.2.2 of Market Rule 1.

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

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

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

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

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

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

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

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

Advisory Qualified Capacity Values are the advisory summer and winter Qualified Capacity values, calculated pursuant to Section III.15.2.5.

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

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

AGC is automatic generation control.

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

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

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

Allowable Capacity Offer Price is a price determined by the Internal Market Monitor as part of its review of Proposed Capacity Offers pursuant to Section III.A.22.2.3.

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

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

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

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

Annual Capacity Auction (ACA) is the Annual Capacity Market auction process carried out pursuant to Section III.15.4 of Market Rule 1.

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

Annual Capacity Auction Offer Window is the period described in the Capacity Auction Calendar during which Capacity Offers must be submitted for an Annual Capacity Auction.

Annual Capacity Market is the annual market for procuring capacity in the New England Control Area, as set forth in Section III.15 of Market Rule 1.

Annual Qualified Capacity is the Qualified Capacity calculated pursuant to Section III.15.3 that is used in an Annual Capacity Auction.

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

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

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

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

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, a Distributed Energy Resource participating as part of a Demand Response Distributed Energy Resource Aggregation, a Settlement Only Distributed Energy Resource Aggregation, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

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

Asset Related Demand is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration; (2) a Storage DARD with a consumption capability of at least 0.1 MW; or (3) one or more storage facilities that are not Electric Storage Facilities with an aggregate consumption capability of at least 1 MW.

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

Asset-Specific Going Forward Costs are the net costs of an asset that is part of a Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Generating Capacity Resources as described in Section III.A.22 (for an asset associated with a Capacity Offer price subject to Internal Market Monitor review) or Section III.A.24 (for an asset submitting a Deactivation Notification).

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

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

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

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

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

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

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

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

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

Average Hourly Load Reduction is either: (i) the sum of the On-Peak Demand Capacity Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Capacity Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand Capacity Resource's or Seasonal Peak Demand Capacity Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.15.2.1.1.2.1 or Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the On-Peak Demand Capacity Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Capacity Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. Electrical energy output and Average Hourly Output shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 or Section III.15.2.1.1.2.1 of Market Rule 1 and the ISO New England Manuals.

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

Bankruptcy Code is the United States Bankruptcy Code.

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

Benchmark Scenario is an Economic Study reference scenario that is described in Section 17.2(a) of Attachment K to the OATT.

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

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

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

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

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

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

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

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

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

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

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

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

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

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

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the

provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day); and (8) with respect to Day-Ahead Ancillary Services Offers administered by the ISO, a quantity with a related price for Day-Ahead Ancillary Services (Day-Ahead Ancillary Services Offers may contain multiple prices for each hour).

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

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

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

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

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

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 or Section III.15.6.1, or; (2) a reconfiguration auction, as described in Section III.13.4 or Section III.15.5.

Capacity Auction Calendar is a calendar published on the ISO's website, as described in Section III.15, detailing dates and deadlines associated with Annual Capacity Market participation, Monthly Reconfiguration Auction participation, and monthly Capacity Supply Obligation Bilateral transactions.

Capacity Auction Offer Price Cap is determined pursuant to Section III.15.1.2.1 of Market Rule 1 prior to the Annual Capacity Auction for each Capacity Commitment Period and is the highest price at which capacity may be offered into the Annual Capacity Auction, unless otherwise expressly allowed by the Tariff.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Capacity Market, as described in Section III.13.7.2.3 or III.15.8.2.3 of Market Rule 1.

Capacity Base Payment is the portion of revenue received in the Forward Capacity Market or Annual Capacity Market as described in Section III.13.7.1 or Section III.15.8.1 of Market Rule 1.

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

Capacity Clearing Price is the clearing price in a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1 or resulting from the Annual Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.15.4.2.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market and Annual Capacity Market.

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

Capacity Demonstration Deadline is a monthly deadline described in the Capacity Auction Calendar for completion of the capacity demonstration requirement set forth in Section III.15.2.6 prior to participation in the Annual Capacity Auction, a Monthly Reconfiguration Auction, or a Capacity Supply Obligation Bilateral transaction.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 or Section III.15.8.5.2 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 or Section III.15.6.2 of Market Rule 1.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 or Section III.15.6 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 or Section III.15.6.2 of Market Rule 1.

Capacity Market is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1, or the annual market for procuring capacity in the New England Control Area, as described in Section III.15 of Market Rule 1.

Capacity Market Commercial Operation is defined in Section III.15.2.6 of Market Rule 1.

Capacity Market Deactivation is the permanent removal of a Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource from the Capacity Market, or the permanent reduction in Capacity Network Import Capability of an External Elective Transmission Upgrade, as described in Section II.I of the OATT.

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

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

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

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

Capacity Offer is an offer submitted for inclusion in the Annual Capacity Auction as set forth in Section III.15.4.1 of Market Rule 1.

Capacity Offer Floor Price is defined in Section III.A.21.3 of Market Rule 1.

Capacity Offer Price Threshold (COPT) is the price specified in Section III.A.22.2.1 of Market Rule 1 associated with the submission, review, and mitigation of prices specified in Capacity Offers submitted for the Annual Capacity Auction.

Capacity Offer Review Submission Deadline is the deadline described in the Capacity Auction Calendar by which proposed Capacity Offers and accompanying documentation must be submitted to the Internal Market Monitor in accordance with Section III.A.22.2.2.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 or Section III.15.8.2 of Market Rule 1.

Capacity Performance Payment Rate is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 or Section III.15.8.2.5 of Market Rule 1.

Capacity Resource is a type of resource eligible to participate in the Annual Capacity Auction. There are four types of Capacity Resources: Generating Capacity Resource, Import Capacity Resource, Demand Capacity Resource, and Distributed Energy Capacity Resource.

Capacity Performance Score is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 or Section III.15.8.2.4 of Market Rule 1.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Capacity Market, as described in Section III.13.7.2.1 or III.15.8.7.2.1 of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2 or an Annual Capacity Auction in accordance with Section III.15.4, a reconfiguration auction in accordance with Section III.13.4 or Section III.15.5, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 or Section III.15.6.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 or Section III.15.6.1 of Market Rule 1.

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4 or Section III.15.8.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 or Section III.15.6.1, or; (2) a reconfiguration auction, as described in Section III.13.4 or Section III.15.5.

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

Capacity Zone Demand Curves are the demand curves used in the Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3 and in Sections III.15.1.1.2 and III.15.1.1.3.

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

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

Category B Designated Blackstart Resource has the same meaning as Designated Blackstart Resource.

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

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

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

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset, the demand reduction capability of a Demand Response Resource, or the demand reduction capability and energy injection capability of a Demand Response Distributed Energy Resource Aggregation.

Cluster has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

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

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

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

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

Cluster Request Window has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

Cluster Restudy has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

Cluster Study has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

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

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

Commercial Capacity is capacity that has achieved FCM Commercial Operation or Capacity Market Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

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

Common Costs are those costs associated with a Station that are avoided only if none of the Generating Capacity Resources composing the Station acquire a Capacity Supply Obligation for the Capacity

Commitment Period, or by the acceptance of the Deactivation Notification of all Generating Capacity Resources composing the Station.

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

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

Composite Capacity Market Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction or Annual Capacity Auction in which multiple Lead Market Participants provide capacity, as described in Section III.13.1.5 or Section III.15.2.8 of Market Rule 1.

Composite Offer Deadline is the deadline for submission of the Composite Offer Form described at Section III.15.2.8.

Composite Offer Form is a form submitted by Lead Market Participants for separate resources seeking to participate as a single composite Capacity Resource in the Annual Capacity Auction, as described in Section III.15.2.8.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Cost-Based Reference Price is a price determined by the Internal Market Monitor for comparison to a price in a Proposed Capacity Offer submitted pursuant to Section III.A.22.2.3.

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

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

Cost of New Entry (CONE) is the estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4 and for each Annual Capacity Auction pursuant to Section III.15.1.2.

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

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

Credit Coverage is third-party credit protection obtained by the ISO in the form of credit insurance coverage.

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

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

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

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

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

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

Cyber Security Exigency is a suspicious or malicious electronic act or event that compromises or attempts to compromise, or disrupts or attempts to disrupt, the ongoing operation of the ISO, the New England Markets, or reliability within the New England Control Area or other electrical facilities directly or indirectly connected to the New England Transmission System and (i) whose severity or nature reasonably requires that the ISO obtain expert assistance not normally called upon to counter such an electronic act or resolve such an event or (ii) whose nature requires the ISO to report such an electronic act or event pursuant to NERC Critical Infrastructure Protection Reliability Standards or applicable regulations promulgated by the Department of Homeland Security, the Department of Energy, or a federal agency with similar cybersecurity responsibilities (or any of their respective successor organizations or agencies).

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

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

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

Day-Ahead Ancillary Services means Day-Ahead Flexible Response Services and Day-Ahead Energy Imbalance Reserve.

Day-Ahead Ancillary Services Avoidable Input Cost is defined in Section III.A.8.2.2 of Appendix A of Market Rule 1.

Day-Ahead Ancillary Services Benchmark Level is defined in Section III.A.8.2 of Appendix A of Market Rule 1.

Day-Ahead Ancillary Services Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Day-Ahead Ancillary Services Offer. Blocks of the Day-Ahead Ancillary Services Offer in effect for each hour will be totaled to determine the quantity of Day-Ahead Ancillary Services Offer Block-Hours for a given day.

Day-Ahead Ancillary Services Expected Close-Out Component is defined in Section III.A.8.2.1 of Appendix A of Market Rule 1.

Day-Ahead Ancillary Services Market means the sale of and payment for Day-Ahead Ancillary Services developed by the ISO as a result of the offers and specifications submitted in accordance with Sections III.1.8 and III.1.10 of Market Rule 1.

Day-Ahead Ancillary Services Offer is an offer that may be submitted by Market Participants in the Day-Ahead Ancillary Services Market in accordance with Section III.1.8.1 of Market Rule 1, and that is used by the ISO to determine obligations for Day-Ahead Ancillary Services as described in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Ancillary Services Strike Price is specified in Section III.1.8.2 of Market Rule 1.

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

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

Day-Ahead Energy Imbalance Reserve is a form of reserve capability that is procured in the Day-Ahead Ancillary Services Market to help satisfy the Forecast Energy Requirement Demand Quantity described in Section III.1.8.4 of Market Rule 1.

Day-Ahead Energy Imbalance Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Sections III.1.8 and III.1.10 of Market Rule 1.

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

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

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

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

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

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

Day-Ahead Flexible Response Services means Day-Ahead Ten-Minute Spinning Reserve, Day-Ahead Ten-Minute Non-Spinning Reserve, and Day-Ahead Thirty-Minute Operating Reserve.

Day-Ahead Flexible Response Services Demand Quantities means Day-Ahead Ten-Minute Spinning Reserve Demand Quantity, Day-Ahead Total Ten-Minute Reserve Demand Quantity, Day-Ahead Minimum Total Reserve Demand Quantity, and Day-Ahead Total Reserve Demand Quantity.

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

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

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

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

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

Day-Ahead Market means the jointly optimized Day-Ahead Energy Market and Day-Ahead Ancillary Services Market.

Day-Ahead Minimum Total Reserve Demand Quantity is described in Section III.1.8.3(c) of Market Rule 1.

Day-Ahead Prices means the prices resulting from the Day-Ahead Market as described in Section III.2.6 of Market Rule 1.

Day-Ahead Ten-Minute Non-Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

Day-Ahead Ten-Minute Non-Spinning Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Demand Quantity is described in Section III.1.8.3(a) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Obligation is described in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Thirty-Minute Operating Reserve is a form of reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

Day-Ahead Thirty-Minute Operating Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Total Ten-Minute Reserve Demand Quantity is described in Section III.1.8.3(b) of Market Rule 1.

Day-Ahead Total Reserve Demand Quantity is described in Section III.1.8.3(d) of Market Rule 1.

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

Deactivation Notification is a notification of the planned New England Market Deactivation or Capacity Market Deactivation of a resource, External Elective Transmission Upgrade, or portion thereof, submitted to the ISO by the applicable Lead Market Participant.

Deactivation Notification Deadline is the deadline for submission of a Deactivation Notification and a Deactivation Notification Package, as discussed in Section II.52.1 of the OATT.

Deactivation Notification Package is information submitted to the ISO, as specified in Section II.52.3 of the OATT, by a resource or External Elective Transmission Upgrade seeking a determination regarding a Deactivation Notification.

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

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

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

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

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

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

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

Demand Bid Cap is $2,000/MWh.

Demand Capacity Resource is a type of resource that may participate in the Capacity Market. There are three Demand Capacity Resource types: Active Demand Capacity Resource, On-Peak Demand Capacity Resource, and Seasonal Peak Demand Capacity Resource.

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

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

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

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

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

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

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

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

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

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

Demand Response Distributed Energy Resource Aggregation (DRDERA) is a type of Distributed Energy Resource Aggregation that is described in additional detail in Section III.6.5.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

Demand Response Resource Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

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

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

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

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

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

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

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

Desired Dispatch Point (DDP) means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

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

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

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

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

Dispatchable Asset Related Demand (DARD) is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions, and must meet the technical requirements specified in the ISO New England Operating Procedures and Manuals.

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

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

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

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

Distributed Energy Capacity Resource (DECR) is a type of Capacity Resource that participates in the Capacity Market and composes one or more Distributed Energy Resource Aggregations.

Distributed Energy Resource (DER) is any resource located on the distribution system, any subsystem thereof or behind a customer meter that is capable of providing energy injection, energy withdrawal, regulation, or demand reduction.

Distributed Energy Resource Aggregation (DERA) is an aggregation of Distributed Energy Resources that is registered under Section III.6.7 and is described in additional detail in Section III.6.

Distributed Energy Resource Aggregator (DER Aggregator) is a Market Participant that aggregates one or more Distributed Energy Resources for participation in a Distributed Energy Resource Aggregation and serves as the Lead Market Participant for a Distributed Energy Resource Aggregation.

Distributed Generation means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

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

Do Not Exceed (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

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

Dynamic De-List Bid is a bid submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, Existing Demand Capacity Resources, and Existing Distributed Energy Capacity

Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

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

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

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

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

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

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

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

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

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

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must

maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study or Economic Studies are studies conducted by the ISO pursuant to the process set out in Section 17 of Attachment K to the OATT.

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

EFT is electronic funds transfer.

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

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

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

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

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

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

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

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

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

EMS is energy management system.

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

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

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

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

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

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

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

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

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

Energy Offer Floor is negative $150/MWh.

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

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

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

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

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

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

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

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

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

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

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

Existing Distributed Energy Capacity Resource is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.2 of Market Rule 1.

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

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

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

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

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

Export Offer Segment is the total MW quantity of a Capacity Offer that is subject to a contract to export capacity outside the New England Control Area during the Capacity Commitment Period associated with the Capacity Offer, whether such MW quantity is delimited by only one price-quantity pair or multiple price-quantity pairs submitted as part of the Capacity Offer pursuant to Section III.15.4.1.

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

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

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

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

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

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

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

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

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

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected

PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Forecast Energy Requirement Demand Quantity is described in Section III.1.8.4 of Market Rule 1.

Forecast Energy Requirement Penalty Factor is a rate, in $/MWh, that is used within the Day-Ahead Market security-constrained economic commitment and dispatch process to reflect the value of forecast energy requirement shortages and is defined in Section III.2.6.2(d) of Market Rule 1.

Forecast Energy Requirement Price is determined in accordance with Section III.2.6.2(b) of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1. The final Forward Capacity Auction was for the Capacity Commitment Period beginning on June 1, 2027.

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

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

Forward Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Forward Reserve Offer Cap is $7,100/megawatt-month.

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

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1. As described in Section III.9.1, the final Forward Reserve Procurement Period shall run from October 1, 2024 through February 28, 2025.

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

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

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

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

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

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

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

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

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

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

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

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

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

Generating Capacity Resource means a type of resource participating in the Capacity Market that meets the qualification requirements for such a resource type specified in Section III.15.2..

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

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

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

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

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

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

Governance Participant is defined in the Participants Agreement.

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

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

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

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

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

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

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

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

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

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

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

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

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

Import Capacity Resource is a type of resource participating in the Capacity Market that meets the qualification requirements for such a resource type specified in Section III.15.2.

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

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

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

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

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

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

Incremental Cost of Reliability Service is described in Section II.54.5 of the OATT..

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

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

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

Initial State of Charge is the State of Charge that an Electric Storage Facility offers at the start of hour one of the Day-Ahead Energy Market.

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

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

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

Interconnection Agreement is the "Large Generator Interconnection Agreement", the "Small Generator Interconnection Agreement", or the "Elective Transmission Upgrade Interconnection Agreement" pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

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

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

Interconnection Reliability Operating Limit (IROL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

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

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

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

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

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

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

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

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

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

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

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

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

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 and 2024-2025 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported

by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

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

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

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

ISO means ISO New England Inc.

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

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

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

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

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

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

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

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

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

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

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

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

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

ITC Agreement is defined in Attachment M to the OATT.

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

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

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

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

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

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

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

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

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

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

Load Management means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

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

Load-Side Relationship Certification is a certification described in Section III.A.21.1.4 that a Lead Market Participant submits as part of a submission of information pursuant to Section III.A.21.1.5 to demonstrate that certain capacity should not be subject to buyer-side market power review.

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

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

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

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

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

Local Longer-Term Transmission Upgrade is any addition, modification, and/or upgrade to the New England Transmission System with a voltage level below 115 kV that is required in connection with the

construction of a Longer-Term Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Section 16 of Attachment K to the OATT.

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

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

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

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

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

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115 kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

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

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

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

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

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

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

Localized Costs are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 and Section 10 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

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

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

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

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

Longer-Term Proposal is a proposal submitted by a Qualified Transmission Project Sponsor pursuant to Section 16.4(b) of Attachment K to the OATT.

Longer-Term Transmission Solution is the Longer-Term Proposal identified as the preferred solution pursuant to Section 16 of Attachment K to the OATT.

Longer-Term Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT. The 2050 Transmission Study shall be the first Longer-Term Transmission Study.

Longer-Term Transmission Upgrade is an addition, modification, and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Longer-Term Transmission Upgrade PTF classification specified in the OATT and has been included in the Regional System Plan and RSP Project List as a Longer-Term Transmission Upgrade pursuant to the procedures described in Section 16 of Attachment K of the OATT.

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

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

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

LSE means load serving entity.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Maximum Daily Award Limit is a parameter that may be submitted as part of a Day-Ahead Ancillary Services Offer, as described in Section III.1.8.1, that expresses the maximum total megawatt-hours of Day-Ahead energy offered or bid and Day-Ahead Ancillary Services offered for the next Operating Day.

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

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

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

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

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

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

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

Maximum State of Charge is the megawatt-hour value of stored energy, submitted by an Electric Storage Facility as part of its Offer Data for a given hour of the Day-Ahead Energy Market, above which the ISO shall not schedule the Electric Storage Facility to receive electricity from the grid.

Measure Life is the estimated time an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the

Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction, Annual Capacity Auction, or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section III.13.1.4.3.1 and Section III.15.2.1.1.2.1 of Market Rule 1 that are submitted by On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1, or as part of the qualification process for the Annual Capacity Auction pursuant to the requirements of Section III.15.2.1.1.2.1 of Market Rule 1, and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource with the monthly settlement

report for the Forward Capacity Market or Annual Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources in operation as of the end of the previous month.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

Minimum State of Charge is the megawatt-hour value of stored energy, submitted by an Electric Storage Facility as part of its Offer Data for a given hour of the Day-Ahead Energy Market, below which the ISO shall not schedule the Electric Storage Facility to inject electricity to the grid.

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

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

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

Monthly Capacity Payment is the Capacity Market payment described in Section III.13.7.3 or Section III.15.8.3 of Market Rule 1.

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

Monthly Qualified Capacity is the amount of a resource's Qualified Capacity eligible to participate in a Monthly Reconfiguration Auction or Capacity Supply Obligation Bilateral during the applicable month.

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

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

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

Monthly Reconfiguration Auction is the reconfiguration auction conducted by the ISO each month as described in Section III.13.4.7 for those Monthly Reconfiguration Auctions held for months prior to the Capacity Commitment Period beginning on June 1, 2028 and in Section III.15.5 for those Monthly Reconfiguration Auctions held for months subsequent to the start of the Capacity Commitment Period beginning on June 1, 2028.

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

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

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

MUI is the market user interface.

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

MW is megawatt.

MWh is megawatt-hour.

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

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

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

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

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

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

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

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

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

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

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

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that

accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

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

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

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

Net CONE is an estimate of the Cost of New Entry, net of non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require to be economically viable given reasonable expectations of the energy and ancillary services revenues under long-term equilibrium conditions.

Net Regional Clearing Price is described in Section III.13.7.5 or Section III.15.8.5 of Market Rule 1.

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

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

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

Network Customer is a Transmission Customer receiving RNS or LNS.

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

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

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired or deactivated; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired or deactivated, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

Network Upgrades has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

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

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

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

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

1.

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

New Capacity Show of Interest Form is a form applicable to the Forward Capacity Market described in Section III.13.1.1.2.1 of Market Rule 1.

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

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

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

New Demand Capacity Resource Show of Interest Form is a form applicable to the Forward Capacity Market described in Section III.13.1.4.1.1.1 of Market Rule 1.

New Distributed Energy Capacity Resource is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.1 of Market Rule 1.

New Distributed Energy Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4A.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource.

New Distributed Energy Capacity Resource Show of Interest Form is a form applicable to the Forward Capacity Market described in Section III.13.1.4A.1.1.1 of Market Rule 1.

NECEC Transmission LLC (NECEC) is defined in Schedule 20B to Section II of this Tariff.

New England Clean Energy Connect Transmission Line (NECEC Transmission Line) is defined in Schedule 20B to Section II of this Tariff.

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

New England Markets Deactivation is the permanent removal of a Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource from all New England Markets, or the permanent reduction in Capacity Network Import Capability and Network Import Capability of an External Elective Transmission Upgrade, as described in Section II.I of the OATT.

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

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

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

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

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

NMPTC means Non-Market Participant Transmission Customer.

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

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

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

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

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.2.1 or Section III.15.8.5.2.1.

Non-Commercial Capacity is the capacity of a resource that cleared in a Forward Capacity Auction for periods prior to the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, or otherwise acquired a Capacity Supply Obligation and remains on Critical Path Schedule monitoring as of June 1, 2028, for some or all of its capacity that acquired a Capacity Supply Obligation.

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

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity

Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

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

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

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

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

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

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

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

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

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

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

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

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

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

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

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

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

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

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

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

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

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

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

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

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

Operations Date is February 1, 2005.

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

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

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

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

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

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

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

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

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

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

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

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4 or Section III.15.7.1.5.4.

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

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

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

Permanent De-list Bid is a bid submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

Policy Scenario is an Economic Study reference scenario that is described in Section 17.2(c) of Attachment K to the OATT.

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

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

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

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

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

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

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

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

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

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

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the

Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

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

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

Proposed Capacity Offer is an offer submitted to the Internal Market Monitor for its review pursuant to Section III.A.22.2.3.

Proportional Impact Method has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Proxy Capacity Offer is a type of offer used in the Annual Capacity Market.

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

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

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

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

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a

rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

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

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

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

Qualification Data Submission Deadline is a date specified in the Capacity Auction Calendar by which a Lead Market Participant seeking to have a resource participate in the Annual Capacity Auction must submit qualification materials pursuant to Section III.15.2.1.1.

Qualification Data Submission Package is the package submitted to the ISO by a Lead Market Participant seeking to qualify a resource for the Annual Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral pursuant to Section III.15.2.1.1.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1 and shall apply to all resources subject to Section III.15.A of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined prior to the 2028-2029 Capacity Commitment Period in the Forward Capacity Market qualification processes, or, for the 2028-2029 Capacity Commitment Period

and all Capacity Commitment Periods thereafter, through the Annual Capacity Market qualification and demonstration processes.

Qualified Capacity Challenge and Restoration Plan Submission Window is the period set forth in the Capacity Auction Calendar during which a Lead Market Participant may challenge the ISO-calculated summer and winter Qualified Capacity values of a Capacity Resource or submit a restoration plan to remedy a significant decrease in a Seasonal Qualified Capacity value of a Capacity Resource.

Qualified Capacity Challenge and Restoration Plan Submission Deadline is a date set forth in the Capacity Auction Calendar by which a Lead Market Participant may challenge the ISO-calculated summer and winter Qualified Capacity values of a Capacity Resource or submit a restoration plan to remedy a significant decrease in Qualified Capacity of a Capacity Resource..

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

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

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

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

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

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

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

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

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

Rationing Minimum Limit is the MW quantity below which a Capacity Offer may not be rationed in the Annual Capacity Auction.

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

Reactive Capability Audit is an audit that measures the ability of a Reactive Resource to provide or absorb reactive power to or from the transmission system at a specified real power output or consumption.

Reactive Resource is a device that dynamically adjusts reactive power output automatically in Real-Time over a continuous range, taking into account control system response bandwidth, within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set-point voltage and include, but are not limited to, Generator Assets, Dispatchable Asset Related Demands that are part of an Electric Storage Facility, and dynamic transmission devices.

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

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

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

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

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

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

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

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

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

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

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

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

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

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

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

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

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

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

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 or Section III.15.7.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

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

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

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

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

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

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

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

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

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

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

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

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

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

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

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as described in Section III.1.7.19 of Market Rule 1.

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

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

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

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

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

Reference Level is defined in Section III.A.7 of Appendix A of Market Rule 1.

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

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses). A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load. A Network Customer's Monthly Regional Network Load shall be calculated in accordance with Section II.21.2 of the OATT.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of

generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide system efficiency benefits as well as reliability benefits to the New England Transmission System.

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

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

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

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

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

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

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

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

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

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

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1, and that are used within the Day-Ahead Market security-constrained economic commitment and dispatch process to reflect the value of Day-Ahead Flexible Response Services shortages and defined in Section III.2.6.2(c) of Market Rule 1.

Reserve Quantity For Settlement is defined in Section III.10.1 of Market Rule 1.

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

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

Resource means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, a Demand Response Resource, a Settlement Only Distributed Energy Resource Aggregation, or a Demand Response Distributed Energy Resource Aggregation.

Resource Adequacy Assessment Qualified Capacity is the amount of summer and winter Qualified Capacity determined pursuant to Section III.15.3 of Market Rule 1 for all Capacity Resources identified in Section III.12.7.2(a) of Market Rule 1, at the start of the Resource Adequacy Assessment process that begins in June of the year preceding the relevant Capacity Commitment Period.

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

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

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

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

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

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

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

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

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

Round-Trip Efficiency is a percentage expressing the megawatt-hours of energy that an Electric Storage Facility injects onto the grid per megawatt-hour of energy it receives from the grid.

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

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

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

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

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

Schedule 20 Service Provider (SSP) references Schedule 20A Service Providers and/or Schedule 20B Service Provider.

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

Schedule 20B Service Provider refers to NECEC as defined in Schedule 20B to Section II of this Tariff.

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

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

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

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

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

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

Seasonal Qualified Capacity Notification Date is a date described in the Capacity Auction Calendar by which the ISO shall notify Market Participants of their Seasonal Qualified Capacity for the upcoming Capacity Commitment Period.

Seasonal Qualified Capacity Values are the summer and winter Qualified Capacity calculated by the ISO pursuant to Section 15.2.7.

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

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

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

Selected Qualified Transmission Project Sponsor is the Qualified Transmission Project Sponsor that proposed the Phase Two Solution, Stage Two Solution, Longer-Term Proposal, or System Efficiency Transmission Upgrade Proposal that has been identified by the ISO as the preferred Phase Two Solution, Stage Two Solution, Longer-Term Transmission Solution, or System Efficiency Transmission Upgrade Solution.

Selected Qualified Transmission Project Sponsor Agreement is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to

provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction in the Day-Ahead Energy Market, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction subject to the conditions specified in Section III.1.10.1A(b)(iii) and (iv). For an External Transaction in the Real-Time Energy Market, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of LMP. Demand Response Resources are not permitted to Self-Schedule.

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

Self-Supplied Capacity Resource is described in Section III.15.2.9.1 of Market Rule 1.

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

Service Agreement is a Transmission Service Agreement or an MPSA.

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

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

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

Settlement Only Distributed Energy Resource Aggregation (SODERA) is a type of Distributed Energy Resource Aggregation and is described in additional detail in Section III.6.6.

Settlement Only Resources are generators of less than 5 MW of maximum net output when operating at any temperature at or above zero degrees Fahrenheit, that meet the metering, interconnection and other requirements in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

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

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

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

SMD Effective Date is March 1, 2003.

Solar High Limit is the estimated power output (MW) of a solar Generator Asset given the Real-Time solar and weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Solar Plant Future Availability is the forecasted Real-Time High Operating Limit of a solar Generator Asset, calculated in the manner described in the ISO Operating Documents.

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

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

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

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

Sponsored Policy Resource is a resource, each asset of which: receives a revenue source, other than revenues from ISO-administered markets, that is supported by a government-regulated rate, charge, or other regulated cost recovery mechanism, and; qualifies as a renewable, clean, zero carbon, or alternative energy asset under a renewable energy portfolio standard, clean energy standard, decarbonization or net-zero carbon standard, alternative energy portfolio standard, renewable energy goal, clean energy goal, or decarbonization or net-zero carbon goal enacted by federal or New England state statute, regulation, or executive or administrative order and as a result of which the asset receives the revenue source.

Stage One Proposal is a first round submission, as defined in Section 4A.6 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.8 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stakeholder-Requested Scenario is an Economic Study reference scenario that is described in Section 17.2(d) of Attachment K to the OATT.

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

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

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

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

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

State of Charge is the total quantity of megawatt-hours available to be injected by an Electric Storage Facility onto the grid.

State-identified Requirement refers to a legal requirement, mandate or policy of a New England state or local government that forms the basis for a Longer-Term Transmission Study request submitted to the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT.

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

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

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

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only if none of the Generating Capacity Resources composing the Station acquire a Capacity Supply Obligation for the Capacity Commitment Period, or by deactivating all Generating Capacity Resources composing the Station.

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

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

Storage as Transmission-Only Asset (SATOA) is electric storage equipment that: (1) is connected to or to be connected to Pool Transmission Facilities in the New England Transmission System at a voltage level of 115 kV or higher; (2) the ISO approved to be included in the Regional System Plan and RSP Project List as a regulated transmission solution and Pool Transmission Facility pursuant to the regional system planning processes in Attachment K of the OATT; and (3) is capable of receiving energy only from the Pool Transmission Facilities and storing the energy for later injection to the Pool Transmission Facilities.

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

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

Substation Network Upgrades has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

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

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) or Section III.15.3.2.1(b) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market

Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

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

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

System-Backed Export is defined in Section III.13.7.2.A.1 and Section III.15.8.2.A.1 of Market Rule 1.

System-Backed Export Charge is calculated in accordance with Section III.13.7.2.A.2 and Section III.15.8.2.A.2 of Market Rule 1.

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

System Efficiency Needs Assessment is defined in Section 17.9 of Attachment K to the OATT.

System Efficiency Needs Scenario is an Economic Study reference scenario that is described in Section 17.2(b) of Attachment K to the OATT.

System Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where financial benefits they provide exceed the cost of the transmission addition or upgrade.

System Efficiency Transmission Upgrade Proposal is a proposal submitted by a Qualified Transmission Project Sponsor pursuant to Section 17.12 of Attachment K to the OATT

System Efficiency Transmission Upgrade Solution is the System Efficiency Transmission Upgrade Proposal identified as the preferred solution pursuant to Section 17.12 of Attachment K to the OATT.

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

System Network Upgrades has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

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

System Operating Limit (SOL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

System-Wide Capacity Demand Curve is the demand curve used in the Capacity Market as specified in Section III.13.2.2 or Section III.15.1.1.1.

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

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

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

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

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

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

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

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

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

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

Thirty-Minute Operating Reserve (TMOR) is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

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

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

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

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

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

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

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

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

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

Transmission Owner means a PTO, MTO or OTO.

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

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

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

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

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

Transitional Cluster Study has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

Transitional CNR Group Study has the meaning specified in Section I of Schedule 22, Section I of 23, and Section I of 25 of the OATT.

UDS is unit dispatch system software.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Virtual Cap is $2,000/MWh.

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

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

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

Wind High Limit is the estimated power output (MW) of a wind Generator Asset given the Real-Time weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Wind Plant Future Availability is the forecasted Real-Time High Operating Limit of a wind Generator Asset, calculated in the manner described in the ISO Operating Documents.

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

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) or Section III.15.3.2.2(b) of Market Rule 1.

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

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

Zonal Capacity Obligation is calculated in accordance with Section III.13.7.5.2 and Section III.15.8.5.2 of Market Rule 1.

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

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

Overview

The procedures and requirements set forth in this ISO New England Financial Assurance Policy shall govern all Applicants, all Market Participants and all Non-Market Participant Transmission Customers. Capitalized terms used in the ISO New England Financial Assurance Policy shall have the meaning specified in Section I.

The purpose of the ISO New England Financial Assurance Policy is (i) to establish minimum criteria for participation in the New England Markets; (ii) to establish a financial assurance policy for Market Participants and Non-Market Participant Transmission Customers that includes commercially reasonable credit review procedures to assess the financial ability of an Applicant, a Market Participant or a Non-Market Participant Transmission Customer to pay for service transactions under the Tariff and to pay its share of the ISO expenses, including amounts under Section IV of the Tariff, and including any applicable Participant Expenses; (iii) to set forth the requirements for alternative forms of security that will be deemed acceptable to the ISO and consistent with commercial practices established by the Uniform Commercial Code that protect the ISO and the Market Participants against the risk of non-payment by other, defaulting Market Participants or by Non-Market Participant Transmission Customers; (iv) to set forth the conditions under which the ISO will conduct business in a nondiscriminatory way so as to avoid the possibility of failure of payment for services rendered under the Tariff; and (v) to collect amounts past due, to collect amounts payable upon billing adjustments, to make up shortfalls in payments, to suspend Market Participants and Non-Market Participant Transmission Customers that fail to comply with the terms of the ISO New England Financial Assurance Policy, to terminate the membership of defaulting Market Participants and to terminate service to defaulting Non-Market Participant Transmission Customers.

I. GROUPS REGARDED AS SINGLE MARKET PARTICIPANTS

In the case of a group of Entities that are treated as a single Market Participant pursuant to Section 4.1 of the Second Restated NEPOOL Agreement (the "RNA"), the group members shall be deemed to have elected to be jointly and severally liable for all debts to Market Participants, PTOs, Non-Market Participant Transmission Customers, NEPOOL and the ISO of any of the group members. For the purposes of the ISO New England Financial Assurance Policy, the term "Market Participant" shall, in the case of a group of members that are treated as a single Market Participant pursuant to Section 4.1 of the RNA, be deemed to refer to the group of members as a whole, and any financial assurance provided

under the ISO New England Financial Assurance Policy will be credited to the account of the group member with the customer identification at the ISO.

II. MARKET PARTICIPANTS' REVIEW AND CREDIT LIMITS

Solely for purposes of the ISO New England Financial Assurance Policy: a "Municipal Market Participant" is any Market Participant that is either (a) a Publicly Owned Entity except for an electric cooperative or an organization including one or more electric cooperatives as used in Section 1 of the RNA or (b) a municipality, an agency thereof, a body politic or a public corporation (i) that is created under the authority of any state or province that is adjacent to one of the New England states, (ii) that is authorized to own, lease and operate electric generation, transmission or distribution facilities and (iii) that has been approved for treatment as a Municipal Market Participant by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee. Market Participants that are not Municipal Market Participants are referred to as "Non-Municipal Market Participants."

A. Minimum Criteria for Market Participation

Any entity participating or seeking to participate in the New England Markets shall comply with the requirements of this Section II.A. For purposes of this Section II.A, the term "customer" shall refer to both Market Participants and Non-Market Participant Transmission Customers and the word "applicant" shall refer to both applicants for Market Participant status and applicants for transmission service from the ISO.

1. Information Disclosure

(a) Each customer and applicant, on an annual basis (by April 30 each year) shall submit a completed information form in the form of (with only minor, non-material changes) and with the information required by Attachment 6 to the ISO New England Financial Assurance Policy. Customer or applicant shall not be required to disclose information required by Attachment 6 if such disclosure is prohibited by law; provided, however, if the disclosure of any information required by Attachment 6 is prohibited by law, then customer or applicant shall use reasonable efforts to obtain permission to make such disclosure. This information shall be treated as Confidential Information, but its disclosure pursuant to subsection (b) below is expressly permitted in accordance with the terms of the ISO New England Information Policy. Customers and applicants may satisfy the requirements above by providing the ISO with filings made to the Securities

and Exchange Commission or other similar regulatory agencies that include substantially similar information to that required above, provided, however, that the customer or applicant must clearly indicate where the specific information is located in those filings. An applicant that fails to provide this information will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this information by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the information to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) The ISO will review the information provided pursuant to subsection (a) above, and will also review whether the customer or applicant or any of the Principals of the customer or applicant are included on any relevant list maintained by the U.S. Office of Foreign Asset Control. If, after review of the information provided pursuant to subsection (a) above or any other information disclosed pursuant to this Section II, the ISO in its sole discretion requires additional information to make its analysis under this subsection (b), the ISO may require additional information from the customer or applicant. If, based on these reviews, the ISO determines that the commencement or continued participation of such customer or applicant in the New England Markets may present an unreasonable risk to those markets or its Market Participants, the Chief Financial Officer of the ISO shall promptly forward to the Participants Committee or its delegate, for its input, such concerns, together with such background materials deemed by the ISO to be necessary for the Participants Committee or its delegate to develop an informed opinion with respect to the identified concerns, including any measures that the ISO may recommend imposing as a condition to the commencement or continued participation in the markets by such customer or applicant (including suspension) or the ISO's recommendation to prohibit or terminate participation by the customer or applicant in the New England Markets. The ISO shall consider the input of the Participants Committee or its delegate before taking any action to address the identified concerns. If the ISO chooses to impose measures other than prohibition (in the case of an applicant) or termination (in the case of a customer) of participation in the New England Markets, then the ISO shall be required to make an informational filing with the Commission as soon as reasonably practicable after taking such action. If the ISO chooses to prohibit (in the case of an applicant) or

terminate (in the case of a customer) participation in the New England Markets, then the ISO must file for Commission approval of such action, and the prohibition or termination shall become effective only upon final Commission ruling. No action by the ISO pursuant to this subsection (b) shall limit in any way the ISO's rights or authority under any other provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy.

2. Risk Management

(a) Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has: (i) either established or contracted for risk management procedures that are applicable to participation in the New England Markets; and (ii) has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) Each applicant prior to commencing activity in the FTR market shall submit to the ISO or its designee the written risk management policies, procedures, and controls, including, if requested by the ISO in its sole discretion, supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant, applicable to its participation in the FTR market relied upon by the Senior Officer of the applicant signing the certificate provided pursuant to Section II.A.2 (a). On an annual basis (by April 30 each year), each Designated FTR Participant with FTR transactions in any of the previous twelve months or in any currently open month

that exceed 1,000 MW per month (on a net basis, as described in the FTR Financial Assurance Requirements provisions in Section VI) shall submit to the ISO or its designee a certificate in the form of Attachment 5 to the ISO New England Financial Assurance Policy stating that, since the customer's delivery of its risk management policies, procedures, and controls (and any supporting documentation, if applicable) or its last certificate pursuant to this Section II.A.2(b), the customer either: (i) has not made any changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable); or (ii) that changes have been made to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) and that all such changes are clearly identified and attached to such certificate. If any such applicant fails to submit the relevant written policies, procedures, and controls, then the applicant will be prohibited from participating in the FTR market. If any such customer fails to provide a certificate in the form of Attachment 5 by end of business on April 30, then the ISO shall issue a notice of such failure to the customer, and if the customer does not provide the certificate to the ISO within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions in the FTR system.

The ISO, at its sole discretion, may also require any applicant or customer to submit to the ISO or its designee the written risk management policies, procedures, and controls, including supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant, that are applicable to its participation in the New England Markets relied upon by the Senior Officer of the applicant or customer signing the certificate provided pursuant to Section II.A.2(a). The ISO may require such submissions based on identified risk factors that include, but are not limited to, the markets in which the customer is transacting or the applicant seeks to transact, the magnitude of the customer's transactions or the applicant's potential transactions, or the volume of the customer's open positions. Where the ISO notifies an applicant or customer that such a submission is required, the submission shall be due within 5 Business Days of the notice. If an applicant fails to submit the relevant written policies, procedures, and controls as required, then the applicant will be prohibited from participating in the New England Markets. If a

customer fails to submit the relevant written policies, procedures, and controls, then the ISO shall issue a notice of such failure to the customer, and if the customer fails to submit the relevant written policies, procedures, and controls to the ISO or its designee within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

The applicant's or customer's written policies, procedures, controls, and any supporting documentation, received by the ISO or its designee pursuant to this subsection (b) shall be treated as Confidential Information.

(c) Where an applicant or customer submits risk management policies, procedures, and controls, or supporting documentation to the ISO or its designee pursuant to any provision of subsection (b) above, the ISO or its designee shall assess that those policies, procedures, and controls conform to prudent risk management practices, which include, but are not limited to: (i) addressing market, credit, and operational risk; (ii) segregating roles, responsibilities, and functions in the organization; (iii) establishing delegations of authority that specify which transactions traders are authorized to enter into; (iv) ensuring that traders have sufficient training in systems and the markets in which they transact; (v) placing risk limits to control exposure; (vi) requiring reports to ensure that risks are adequately communicated throughout the organization; (vii) establishing processes for independent confirmation of executed transactions; and (viii) establishing periodic valuation or mark-to-market of risk positions as appropriate.

Where, as a result of the assessment described above in this subsection (c), the ISO or its designee believes that the applicant's or customer's written policies, procedures, and controls do not conform to prudent risk management practices, then the ISO or its designee shall provide notice to the applicant or customer explaining the deficiencies. The applicant or customer shall revise its policies, procedures, and controls to address the deficiencies within 55 days after issuance of such notice. (If April 30 falls within that 55 day window, the ISO may choose not to require a separate submission on April 30 as described in subsection (b) above.) If an applicant's revised written policies, procedures, and controls do not adequately address the deficiencies identified in the notice, then the applicant will be prohibited from participating in the New England Markets. If a customer's revised written policies, procedures, and controls do not adequately address

the deficiencies identified in the notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

3. Communications

Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has either established or contracted to establish procedures to effectively communicate with and respond to the ISO with respect to matters relating to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy. Such procedures must ensure, at a minimum, that at least one person with the ability and authority to address matters related to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy on behalf of the customer or applicant, including the ability and authority to respond to requests for information and to arrange for additional financial assurance as necessary, is available from 9:00 a.m. to 5:00 p.m. Eastern Time on Business Days. Such procedures must also ensure that the ISO is kept informed about the current contact information (including phone numbers and e-mail addresses) for the person or people described above. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

4. Capitalization

(a) To be deemed as meeting the capitalization requirements, a customer or applicant shall either:

(i) be Rated and have a Governing Rating that is an Investment Grade Rating of BBB-/Baa3 or higher;

(ii) maintain a minimum Tangible Net Worth of one million dollars; or

(iii) maintain a minimum of ten million dollars in total assets, provided that, to meet this requirement, a customer or applicant may supplement total assets of less than ten million dollars with additional financial assurance in an amount equal to the difference between ten million dollars and the customer's or applicant's total assets in one of the forms described in Section X (any additional financial assurance provided pursuant to this Section II.A.4(a) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy).

(b) Any customer or applicant that fails to meet these capitalization requirements will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions of a duration greater than one month in the FTR system or any future transactions for a duration of one month or less except when FTRs for a month are being auctioned for the final time. Such a customer or applicant may enter into future transaction of a duration of one month or less in the FTR system in the case of FTRs for a month being auctioned for the final time. Any customer or applicant that fails to meet these capitalization requirements shall provide additional financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy equal to 25 percent of the customer's or applicant's FTR Financial Assurance Requirements. Any additional financial assurance provided pursuant to this Section II.A.4(b) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

(c) For markets other than the FTR market:

(i) Where a customer or applicant fails to meet the capitalization requirements, the customer or applicant will be required to provide an additional amount of financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy in an amount equal to 25 percent of the customer's or applicant's total financial assurance requirement, excluding the following:

- FTR Financial Assurance Requirements; and
- FCM Delivery Financial Assurance for customers or applicants that are assessed as medium risk or high risk per the Corporate Liquidity

Assessment (as described in Section VII.A below) from the start of the Capacity Commitment Period related to the sixteenth Forward Capacity Auction (i.e., June 1, 2025) or any Capacity Commitment Period thereafter.

(ii) An applicant that fails to provide the full amount of additional financial assurance required as described in subsection (i) above will be prohibited from participating in the New England Markets until the deficiency is rectified. For a customer, failure to provide the full amount of additional financial assurance required as described in subsection (i) above will have the same effect and will trigger the same consequences as exceeding the "100 Percent Test" as described in Section III.B.2.c of the ISO New England Financial Assurance Policy.

(iii) Any additional financial assurance provided pursuant to this Section II.A.4(c) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

5. Additional Eligibility Requirements

All customers and applicants shall at all times be:

(a) An "appropriate person," as defined in sections 4(c)(3)(A) through (J) of the Commodity Exchange Act (7 U.S.C. § 1 *et seq.*);
(b) An "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or
(c) A "person who actively participates in the generation, transmission, or distribution of electric energy," as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

Each customer must demonstrate compliance with the requirements of this Section II.A.5 by submitting to the ISO on or before September 15, 2013 a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the customer is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately

cease all participation in the New England Markets. If the customer is relying on section 4(c)(3)(F) of the Commodity Exchange Act, it shall accompany the certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the customer's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy. The certificate must be signed on behalf of the customer by a Senior Officer of the customer. A customer that fails to provide this certificate by September 15, 2013 shall be immediately suspended and the ISO shall initiate termination proceedings against the customer.

Each applicant must submit with its membership application a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the applicant is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately cease all participation in the New England Markets. If the applicant is relying on section 4(c)(3)(F) of the Commodity Exchange Act, it shall accompany the certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the applicant's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy. The certificate must be signed on behalf of the applicant by a Senior Officer of the applicant.

The ISO, at its sole discretion, may require any applicant or customer to submit to the ISO documentation in support of the certification provided pursuant to this Section II.A.5. If at any time the ISO becomes aware that a customer no longer satisfies the requirements of this Section II.A.5, the customer shall be immediately suspended and the ISO shall initiate termination proceedings against the customer.

6. Prior Uncured Defaults

In addition to, and not in limitation of Section IV of the ISO New England Financial Assurance Policy, an applicant who has a previous uncured payment default must cure such payment default by payment to the ISO of all outstanding and unpaid obligations, as well as meet all requirements for participation in the New England Markets contained in the ISO New England Financial Assurance Policy. For purposes of this Section II.A.6 and the ISO's evaluation of information disclosed pursuant to Section II of the ISO New England Financial Assurance Policy, the ISO will evaluate relevant factors to determine if an entity seeking to participate in the New England Markets under a different name, affiliation, or organization, should be treated as the same customer or applicant that experienced the previous payment default. Such factors may include, but are not limited to, the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base, and the business engaged in prior to the attempted re-entry. Notwithstanding the foregoing, an applicant shall not be required to cure a payment default that has lawfully been discharged pursuant to the U.S. Bankruptcy Code.

B. Proof of Financial Viability for Applicants

Each Applicant must, with its membership application and at its own expense, submit proof of financial viability, as described below, satisfying the ISO requirements to demonstrate the Applicant's ability to meet its obligations. Each Applicant that intends to establish a Market Credit Limit or a Transmission Credit Limit of greater than $0 under Section II.D or Section II.E below must submit to the ISO all current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch (collectively, the "Rating Agencies"). Each Applicant, whether or not it intends to establish a Market Credit Limit or Transmission Credit Limit of greater than $0, must submit to the ISO audited financial statements for the two most recent years, or the period of its existence, if less than two years, and unaudited financial statements for its last concluded fiscal quarter if they are not included in such audited annual financial statements. These unaudited statements must be certified as to their accuracy by a Senior Officer of such Applicant, which, for purposes of ISO New England Financial Assurance Policy, means an officer of the subject entity with the title of vice president (or similar office) or higher,

or another officer designated in writing to the ISO by that officer. These audited and unaudited statements must include in each case, but are not limited to, the following information to the extent available: balance sheets, income statements, statements of cash flows and notes to financial statements, annual and quarterly reports, and 10-K, 10-Q and 8-K Reports. If any of these financial statements are available on the internet, the Applicant may provide instead a letter to the ISO stating where such statement may be located and retrieved. If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO, at the ISO's sole discretion (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-alone subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; or (iii) compiled statements).

In addition, each Applicant, whether or not it intends to establish a Market Credit Limit or a Transmission Credit Limit, must submit to the ISO: (i) at least one (1) bank reference and three (3) utility company credit references, or in those cases where an Applicant does not have three (3) utility company credit references, three (3) major trade payable vendor references may be substituted; and (ii) relevant information as to any known or anticipated material lawsuits, as well as any prior bankruptcy declarations by the Applicant, or by its predecessor(s), if any; and (iii) a completed ISO credit application. In the case of certain Applicants, some of the information and documentation described in items (i) and (ii) of the immediately preceding sentence may not be applicable or available, and alternate requirements may be specified by the ISO or its designee in its sole discretion.

The ISO will not begin its review of a Market Participant's credit application or the accompanying material described above until full and final payment of that Market Participant's application fee.

The ISO shall prepare a report, or cause a report to be prepared, concerning the financial viability of each Applicant. In its review of each Applicant, the ISO or its designee shall consider all of the information and documentation described in this Section II. All costs

incurred by the ISO in its review of the financial viability of an Applicant shall be borne by such Applicant and paid at the time that such Applicant is required to pay its first annual fee under the Participants Agreement. For an Applicant applying for transmission service from the ISO, all costs incurred by the ISO shall be paid prior to the ISO's filing of a Transmission Service Agreement. The report shall be provided to the Participants Committee or its designee and the affected Applicant within three weeks of the ISO's receipt of that Applicant's completed application, application fee, and Initial Market Participant Financial Assurance Requirement, unless the ISO notifies the Applicant that more time is needed to perform additional due diligence with respect to its application.

C. Ongoing Review and Credit Ratings

1. Rated and Credit Qualifying Market Participants

A Market Participant that (i) has a corporate rating from one or more of the Rating Agencies, or (ii) has senior unsecured debt that is rated by one or more of the Rating Agencies, is referred to herein as "Rated." A Market Participant that is not Rated is referred to herein as "Unrated."

For all purposes in the ISO New England Financial Assurance Policy, for a Market Participant that is Rated, the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt, shall be the "Governing Rating."

A Market Participant that is: (i) Rated and whose Governing Rating is an Investment Grade Rating; or (ii) Unrated and that satisfies the Credit Threshold is referred to herein as "Credit Qualifying." A Market Participant that is not Credit Qualifying is referred to herein as "Non-Qualifying."

For purposes of the ISO New England Financial Assurance Policy, "Investment Grade Rating" for a Market Participant (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the

Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

2. Unrated Market Participants

Any Unrated Market Participant that (i) has not been a Market Participant in the ISO for at least the immediately preceding 365 days; or (ii) has defaulted on any of its obligations under the Tariff (including without limitation its obligations hereunder and under the ISO New England Billing Policy) during such 365-day period; or (iii) is an FTR-Only Customer; or (iv) does not have a Current Ratio of at least 1.0, a Debt-to-Total Capitalization Ratio of 0.6 or less, and an EBITDA-to-Interest Expense Ratio of at least 2.0 must provide an appropriate form of financial assurance as described in Section X below. An Unrated Market Participant that does not meet any of the conditions in clauses (i), (ii), (iii) and (iv) of this paragraph is referred to herein as satisfying the "Credit Threshold."

For purposes of the ISO New England Financial Assurance Policy, "Current Ratio" on any date is all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO; "Debt-to-Total Capitalization Ratio" on any date is a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO; and "EBITDA-to-Interest Expense Ratio" on any date is a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO. The "Debt-to-Total Capitalization Ratio" will not be considered for purposes of determining whether a Municipal Market Participant satisfies the Credit Threshold. Each of the ratios described in this paragraph shall be determined in accordance with international

accounting standards or generally accepted accounting principles in the United States at the time of determination consistently applied.

3. Information Reporting Requirements for Market Participants

Each Market Participant having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis within 10 days of its becoming available and within 65 days after the end of the applicable fiscal quarter of such Market Participant, its balance sheet, which shall show sufficient detail for the ISO to assess the Market Participant's Tangible Net Worth. Unrated Market Participants having a Market Credit Limit or Transmission Credit Limit greater than zero shall also provide additional financial statements, which shall show sufficient detail for the ISO to calculate such Unrated Market Participant's Current Ratio, Debt-to-Total Capitalization Ratio and EBITDA-to-Interest Expense Ratio. In addition, each Market Participant having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of their becoming available and within 120 days after the end of the fiscal year of such Market Participant, balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). If any of this financial information is available on the internet, the Market Participant may provide instead a letter to the ISO stating where such information may be located and retrieved. If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-alone subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; (iii) compiled statements; (iv) internally prepared statements; or (v) tax returns).

Except in the case of a Market Participant or Unrated Market Participant that submits audited financial statements to the ISO, financial statements submitted to the ISO pursuant to this Section II.C.3 shall be accompanied by a written statement from a Senior Officer of the Market Participant or Unrated Market Participant certifying the accuracy of those financial statements. If an attestation was made by an independent accounting firm, then the written statement shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required.

Notwithstanding any other provision in this subsection, the ISO may require any Market Participant to submit the financial statements and other information described in this subsection. The Market Participant shall provide the requested statements and other information within 10 days of such request. If a Market Participant fails to provide financial statements or other information as requested and the ISO determines that the Market Participant poses an unreasonable risk to the New England Markets, then the ISO may request that the Market Participant provide additional financial assurance in an amount no greater than $10 million, or take other measures to substantiate the Market Participant's ability to safely transact in the New England Markets (any additional financial assurance provided pursuant to this Section II.C.3 shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy). If the Market Participant fails to comply with such a request from the ISO, then the ISO may issue a notice of suspension or termination to the Market Participant. If the Market Participant fails to comply with the ISO's request within 5 Business Days from the date of issuance of the notice of suspension or termination, then the ISO may suspend or terminate the Market Participant.

A Market Participant may choose not to submit financial statements as described in this Section II.C.3, in which case the ISO shall use a value of $0.00 for the Market Participant's total assets and Tangible Net Worth for purposes of the capitalization assessment described in Section II.A.4(a) and such Market Participant's Market Credit Limit and Transmission Credit Limit shall be $0.00.

A Market Participant may choose to provide additional financial assurance in an amount equal to $10 million in lieu of providing financial statements under this Section II.C.3.

Such amount shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy but shall be sufficient to meet the capitalization requirements in Section II.A.4(a)(iii).

D. Market Credit Limits

A credit limit for a Market Participant's Financial Assurance Obligations except FTR Financial Assurance Requirements (a "Market Credit Limit") shall be established for each Market Participant in accordance with this Section II.D.

1. Market Credit Limit for Non-Municipal Market Participants

A "Market Credit Limit" shall be established for each Rated Non-Municipal Market Participant in accordance with subsection (a) below, and a Market Credit Limit shall be established for each Unrated Non-Municipal Market Participant in accordance with subsection (b) below.

a. Market Credit Limit for Rated Non-Municipal Market Participants

As reflected in the following table, the Market Credit Limit of each Rated Non-Municipal Market Participant (other than an FTR-Only Customer) shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Municipal Market Participant's Tangible Net Worth as listed in the following table, (ii) $50 million, or (iii) 20 percent (20%) of the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers ("TADO").

Investment Grade Rating		**Percentage of Tangible Net Worth**
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%
AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%

A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

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

b. Market Credit Limit for Unrated Non-Municipal Market Participants

The Market Credit Limit of each Unrated Non-Municipal Market Participant that satisfies the Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Municipal Market Participant's Tangible Net Worth, (ii) $25 million or (iii) 20 percent (20%) of TADO. The Market Credit Limit of each Unrated Non-Municipal Market Participant that does not satisfy the Credit Threshold shall be $0.

2. Market Credit Limit for Municipal Market Participants

The Market Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to the lesser of (i) 20 percent (20%) of TADO and (ii) $25 million. The Market Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum

of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million.

E. Transmission Credit Limits

A "Transmission Credit Limit" shall be established for each Market Participant in accordance with this Section II.E, which Transmission Credit Limit shall apply in accordance with this Section II.E. A Transmission Credit Limit may not be used to meet FTR Financial Assurance Requirements.

1. Transmission Credit Limit for Rated Non-Municipal Market Participants

The Transmission Credit Limit of each Rated Non-Municipal Market Participant shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Municipal Market Participant's Tangible Net Worth as listed in the following table or (ii) $50 million:

Investment Grade Rating		**Percentage of Tangible Net Worth**
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%
AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%
A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

2. Transmission Credit Limit for Unrated Non-Municipal Market Participant

The Transmission Credit Limit of each Unrated Non-Municipal Market Participant that satisfies the Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Municipal Market Participant's Tangible Net

Worth or (ii) $25 million. The Transmission Credit Limit of each Unrated Non-Municipal Market Participant that does not satisfy the Credit Threshold shall be $0.

3. Transmission Credit Limit for Municipal Market Participants

The Transmission Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to $25 million. The Transmission Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million.

F. Credit Limits for FTR-Only Customers

The Market Credit Limit and Transmission Credit Limit of each FTR-Only Customer shall be $0.

G. Total Credit Limit

The sum of a Rated Non-Municipal Market Participant's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change, each Rated Non-Municipal Market Participant that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the limit set forth in Section II.D.1.a above) and its Transmission Credit Limit (up to the limit set forth in Section II.E.1 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Municipal Market Participant may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Municipal Market Participant does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates. If the sum of the amounts for Affiliates is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate,

or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

III. MARKET PARTICIPANTS' REQUIREMENTS

Each Market Participant that provides the ISO with financial assurance pursuant to this Section III must provide the ISO with financial assurance in one of the forms described in Section X below and in an amount equal to the amount required in order to avoid suspension under Section III.B below (the "Market Participant Financial Assurance Requirement"). A Market Participant's Market Participant Financial Assurance Requirement shall remain in effect as provided herein until the later of (a) 150 days after termination of the Market Participant's membership or (b) the end date of all FTRs awarded to the Market Participant and the final satisfaction of all obligations of the Market Participant providing that financial assurance; provided, however that financial assurances required by the ISO New England Financial Assurance Policy related to potential billing adjustments chargeable to a terminated Market Participant shall remain in effect until such billing adjustment request is finally resolved in accordance with the provisions of the ISO New England Billing Policy. Furthermore and without limiting the generality of the foregoing, (i) any portion of any financial assurance provided under the ISO New England Financial Assurance Policy that relates to a Disputed Amount shall not be terminated or returned prior to the resolution of such dispute, even if the Market Participant providing such financial assurance is terminated or voluntarily terminates its MPSA and otherwise satisfies all of its obligations to the ISO and (ii) the ISO shall not return or permit the termination of any financial assurance provided under the ISO New England Financial Assurance Policy by a Market Participant that has terminated its membership or been terminated to the extent that the ISO determines in its reasonable discretion that that financial assurance will be required under the ISO New England Financial Assurance Policy with respect to an unsettled liability or obligation owing from that Market Participant.

A Market Participant that knows that it is not satisfying its Market Participant Financial Assurance Requirement shall notify the ISO immediately of that fact.

A. Determination of Financial Assurance Obligations

For purposes of the ISO New England Financial Assurance Policy:

(i) a Market Participant's "Hourly Requirements" at any time will be the sum of (x) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Hourly

Charges (excluding Daily FCM Charges) for such Market Participant that have been settled but not invoiced, plus (z) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been cleared but not settled which amount shall be calculated by the Hourly Charges Estimator. The Hourly Charges Estimator (which amount shall not be less than $0) shall be determined by the following formula:

$$\text{Hourly Charges Estimator} = \sum_{i=t-n+1}^{t} HC_i \times \text{LMP ratio} \times 1.15$$

Where:

t = The last day that such Market Participant's Hourly Charges (excluding Daily FCM Charges) are fully settled;

n = The number of days that such Market Participant's Day-Ahead Energy has been cleared but not settled;

HC = The Hourly Charges (excluding Daily FCM Charges) for such Market Participant for a fully settled day; and

LMP ratio = The average Day-Ahead Prices at the New England Hub over the period of cleared but not settled n days divided by the average Day-Ahead Prices at the New England Hub over the period of most recent fully settled n days. For purposes of this Section III.A.(i), the "New England Hub" shall mean the Hub located in Western and Central Massachusetts referred to as .H.INTERNAL_HUB;

(ii) A Market Participant's "Daily FCM Requirements" at any time will be the sum of (x) the Daily FCM Charges that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Daily FCM Charges that have been settled but not invoiced, plus (z) the Daily FCM Charges for such Market Participant that have been incurred but not settled which amount shall be calculated by the Daily FCM Obligation Estimator. The Daily FCM Obligation Estimator (which amount shall not be less than $0) shall be determined by the following formula:

Daily FCM Obligation Estimator = MAX(FCM_Daily_Credit_CM x NDAY_CM + FCM_Daily_Credit_PM x NDAY_PM + FCM_Charge_LD x NDAY_P2 x FCA_Price_Ratio, 0)

Where:

FCM_Daily_Credit_CM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the current month;

FCM_Daily_Credit_PM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the month preceding the current month;

NDAY_CM is the number of days in the current month within the period from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

NDAY_PM is the number of days in the month preceding the current month within the period from the last day of the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

FCM_Charge_LD is the portion of the Daily FCM Charges that corresponds to Capacity Load Obligations for the Market Participant from the last day the Daily FCM Charges have been settled; and

NDAY_P2 is the number of days from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed) plus 2.

The FCA_Price_Ratio shall be calculated as the weighted average of the Capacity Clearing Prices for the Rest-of-Pool Capacity Zone for the relevant Capacity Commitment Periods divided by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day the Daily FCM Charges have been settled, as determined by the following formula:

$FCA_Price_Ratio = (((Clearing\ Price_CCP_n \times NDAY_P2_CCP_n) + (Clearing\ Price_CCP_{n+1} \times NDAY_P2_CCP_{n+1}))/NDAY_P2)/(Clearing\ Price_CCP_n)$

Where:

$Clearing\ Price_CCP_n$ is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day that the Daily FCM Charges have been settled;

$Clearing\ Price_CCP_{n+1}$ is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone for the Capacity Commitment Period following CCP_n;

$NDAY_P2_CCP_n$ is number of days in the CCP_n within NDAY_P2; and

$NDAY_P2_CCP_{n+1}$ is number of days in the CCP_{n+1} within NDAY_P2.

(iii) a Market Participant's "Non-Hourly Requirements" at any time will be determined by averaging that Market Participant's Non-Hourly Charges but not include: (A) the amount due from or to such Market Participant for FTR transactions, (B) any amounts due from such Market Participant for the Forward Capacity Market or System-Backed Export transactions, (C) any amounts due under Section 14.1 of the RNA, (D) any amounts due for NEPOOL GIS API Fees, and (E) the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Market Participant) over the two most recently invoiced calendar months; provided that such Non-Hourly Requirements shall in no event be less than zero;

(iv) a Market Participant's "Transmission Requirements" at any time will be determined by averaging that Market Participant's Transmission Charges over the two most recently invoiced calendar months; provided that such Transmission Requirements shall in no event be less than $0;

(v) a Market Participant's Virtual Requirements at any time will equal the amount of all unsettled Increment Offers and Decrement Bids submitted by such Market Participant at such time (which amount of unsettled Increment Offers and Decrement Bids will be calculated by the ISO according to a methodology approved from time to time by the NEPOOL Budget and Finance Subcommittee and posted on the ISO's website);

(vi) a Market Participant's "Financial Assurance Obligations" at any time will be equal to the sum at such time of:

a. such Market Participant's Hourly Requirements; plus
b. such Market Participant's Daily FCM Requirements; plus
c. such Market Participant's Virtual Requirements; plus
d. such Market Participant's Non-Hourly Requirements times 2.50 (subject to Section X.D with respect to Provisional Members); plus
e. such Market Participant's "FTR Financial Assurance Requirements" under Section VI below; plus
f. such Market Participant's "FCM Financial Assurance Requirements" under Section VII below; plus

g. such Market Participant's "IEP Financial Assurance Requirement" under Section III.D below; plus

h. the amount of any Disputed Amounts received by such Market Participant; and

(vii) a Market Participant's "Transmission Obligations" at any time will be such Market Participant's Transmission Requirements times 2.50.

To the extent that the calculations of the components of a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) as described above produce positive and negative values, such components may offset each other; provided, however, that a Market Participant's Financial Assurance Obligations shall never be less than zero.

B. Credit Test Calculations and Allocation of Financial Assurance, Notice and Suspension from the New England Markets

1. Credit Test Calculations and Allocation of Financial Assurance

The financial assurance provided by a Market Participant shall be applied as described in this Section.

(a) "Market Credit Test Percentage" is equal to a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) divided by the sum of its Market Credit Limit and any financial assurance allocated as described in subsection (d) below.

(b) "FTR Credit Test Percentage" is equal to a Market Participant's FTR Financial Assurance Requirements divided by any financial assurance allocated as described in subsection (d) below.

(c) "Transmission Credit Test Percentage" is equal to a Market Participant's Transmission Obligations divided by the sum of its Transmission Credit Limit and any financial assurance allocated as described in subsection (d) below.

(d) A Market Participant's financial assurance shall be allocated as follows:

(i) financial assurance shall be first allocated so as to ensure that the Market Participant's Market Credit Test Percentage is no greater that 100%;

(ii) any financial assurance that remains after the allocation described in subsection (d) (i) shall be allocated so as to ensure that the Market Participant's FTR Credit Test Percentage is no greater than 100%;

(iii) any financial assurance that remains after the allocation described in subsection (d) (ii) shall be allocated so as to ensure that the Market Participant's Transmission Credit Test Percentage is no greater than 100%;

(iv) if any financial assurance remains after the allocations described in subsection (d) (iii), then that remaining financial assurance shall be allocated by repeating the steps described in subsections (d) (i), (d) (ii), and (d) (iii) to ensure that the respective test percentages are no greater than 89.99%;

(v) if any financial assurance remains after the allocation described in subsection (d) (iv), then that remaining financial assurance shall be allocated by repeating the steps described in subsections (d) (i), (d) (ii), and (d) (iii) to ensure that the respective test percentages are no greater than 79.99%;

(vi) any financial assurance that remains after the allocations described in subsection (d) (v) shall be allocated to the Market Credit Test Percentage.

2. Notices

a. 80 Percent Test

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%), the ISO shall issue notice thereof to such Market Participant.

b. 90 Percent Test

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage equals or exceeds 90 percent (90%) , then, in addition to the actions to be taken when the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%), the ISO shall issue notice thereof to such Market Participant. The ISO shall also issue a 90 percent (90%) notice to a Market Participant and take certain other actions under the circumstances described in Section III.B.2.c below.

c. 100 Percent Test

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) or when the sum of the financial assurance and credit limits of a Market Participant that has financial assurance requirements equal zero, then, in addition to the actions to be taken when the

Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%) and 90 percent (90%), (i) the ISO shall issue notice thereof to such Market Participant, (ii) that Market Participant shall be immediately suspended from submitting Increment Offers and Decrement Bids until such time when its Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are less than or equal to 100 percent (100%), and (iii) if sufficient financial assurance to lower the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 100 percent (100%) or, in the case of a Market Participant that has received one to five notices that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) in the previous 365 days (not including the instant notice), sufficient financial assurance to lower such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 90 percent (90%), is not provided by 8:30 a.m. Eastern Time on the next Business Day, (a) the event shall be a Financial Assurance Default; (b) the ISO shall issue notice thereof to such Market Participant, to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contacts for all Market Participants, and (c) such Market Participant shall be suspended from: (1) the New England Markets, as provided below; (2) receiving transmission service under any existing or pending arrangements under the Tariff or scheduling any future transmission service under the Tariff; (3) voting on matters before the Participants Committee and NEPOOL Technical Committees; (4) entering into any future transactions in the FTR system; and (5) submitting an offer of Non-Commercial Capacity in any Forward Capacity Auction or any reconfiguration auction in the Forward Capacity Market, in each case until such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are at 100 percent (100%) or less. In addition to all of the provisions above, any Market Participant that has received six or more notices in the previous 365 days that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage has exceeded 100 percent (100%) shall receive a notice thereof and shall be required to maintain sufficient financial assurance to keep such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage at less than or equal to 90

percent (90%). If such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage exceeds 90 percent (90%), the ISO shall issue a notice thereof to such Market Participant. If sufficient financial assurance to lower such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 90 percent (90%) is not provided by 8:30 a.m. Eastern Time on the next Business Day, then the consequences described in subsections (a), (b) and (c) of Section III.B.2.c (iii) above shall apply until such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are at 90 percent (90%) or less.

However, when a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) or 90 percent (90%), as applicable under this Section III.B.2.c, solely because its Investment Grade Rating is downgraded by one grade and the resulting grade is BBB-/Baa3 or higher, then (x) for five Business Days after such downgrade, such downgrade shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage and (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such downgrade if such Market Participant cures such default within such five Business Day period. When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent solely because a letter of credit is valued at $0 prior to the termination of that letter of credit, as described in Section X.B, then the ISO, in its sole discretion, may determine that: (x) for five Business Days after such change in the valuation of the letter of credit, such valuation shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage; and/or (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such valuation if such Market Participant cures such default within such five Business Day period.

Notwithstanding the foregoing, a Market Participant shall neither (x) receive a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) nor (y) be suspended under this Section

III.B if (i) the amount of financial assurance necessary for that Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to get to 100 percent (100%) or lower is less than $1,000 or (ii) that Market Participant's status with the ISO has been terminated.

3. Suspension from the New England Markets

a. General

The suspension of a Market Participant, and any resulting annulment, termination or removal of OASIS reservations, removal from the settlement system and the FTR system, suspension of the ability to offer Non-Commercial Capacity or participate in a substitution auction in the Forward Capacity Market, drawing down of financial assurance, rejection of Increment Offers and Decrement Bids, and rejection of bilateral transactions submitted to the ISO, shall not limit, in any way, the ISO's right to invoice or collect payment for any amounts owed (whether such amounts are due or becoming due) by such suspended Market Participant under the Tariff or the ISO's right to administratively submit a bid or offer of a Market Participant's Non-Commercial Capacity in any Forward Capacity Auction or any reconfiguration auction or to make other adjustments under Market Rule 1.

In addition to the notices provided herein, the ISO will provide any additional information required under the ISO New England Information Policy.

Each notice issued by the ISO pursuant to this Section III.B shall indicate whether the subject Market Participant has a registered load asset. If the ISO has issued a notice pursuant to this Section III.B and subsequently the subject Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are equal to or less than 100 percent (100%), such Market Participant may request the ISO to issue a notice stating such fact. However, the ISO shall not be obligated to issue such a notice unless, in its sole discretion, the ISO concludes that such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are equal to or less than 100 percent (100%).

Notwithstanding the foregoing, if a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 90 percent (90%) as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, and, but for such Increment Offers and/or Decrement Bids or such bilateral transactions, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, a notice will not be issued.

If a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, and, but for such Increment Offers and/or Decrement Bids or such bilateral transactions, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, a notice will be issued only to such Market Participant, and such Market Participant shall be "suspended" as described below.

Any such suspension as a result of one or more Increment Offers or Decrement Bids submitted by a Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, shall take effect immediately upon submission of such Increment Offers and/or Decrement Bids or such bilateral transactions to remain in effect until such Market Participant is in compliance with the ISO New England Financial Assurance Policy, notwithstanding any provision of this Section III.B to the contrary.

If a Market Participant is suspended from the New England Markets in accordance with the provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy, then the provisions of this Section III.B shall control notwithstanding any other provision of the Tariff to the contrary. A suspended Market Participant shall have no ability so long as it is suspended (i) to be reflected in the ISO's settlement system, including any bilateral transactions, as either a purchaser or a seller of any products or services sold through the New England Markets (other than (A) Commercial Capacity and (B) Non-Commercial Capacity during the Non-Commercial

Capacity Cure Period) that cause such suspended Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the Market Participants, (ii) to submit Demand Bids, Decrement Bids or Increment Offers in the New England Markets, (iii) to submit offers for Non-Commercial Capacity in any Forward Capacity Auction or reconfiguration auction or acquire Non-Commercial Capacity through a Capacity Supply Obligation Bilateral, or (iv) to submit supply offers or demand bids in any Forward Capacity Market substitution auction. Any transactions, including bilateral transactions with a suspended Market Participant (other than transactions for (A) Commercial Capacity and (B) Non-Commercial Capacity during the Non-Commercial Capacity Cure Period) that cause such suspended Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the other Market Participants and any Demand Bids, Decrement Bids, Increment Offers, and Export Transactions submitted by a suspended Market Participant shall be deemed to be terminated for purposes of the Day-Ahead Energy Market clearing and the ISO's settlement system. If a Market Participant has provided the financial assurance required for a Capacity Supply Obligation Bilateral or Annual Reconfiguration Transaction, then that Capacity Supply Obligation Bilateral or Annual Reconfiguration Transaction, respectively, will not be deemed to be terminated when that Market Participant is suspended.

b. Load Assets

Any load asset registered to a suspended Market Participant shall be terminated, and the obligation to serve the load associated with such load asset shall be assigned to the relevant unmetered load asset(s) unless and until the host Market Participant for such load assigns the obligation to serve such load to another asset. If the suspended Market Participant is responsible for serving an unmetered load asset, such suspended Market Participant shall retain the obligation to serve such unmetered load asset. If a suspended Market Participant has an ownership share of a load asset, such ownership share shall revert to the Market Participant that assigned such ownership share to such suspended Market Participant. If a suspended Market Participant has the obligation under the Tariff or otherwise to offer any of its supply or to bid any pumping load to provide products or services sold through the New England Markets, that obligation shall continue, but only in Real-Time, notwithstanding the Market Participant's suspension, and such offer or bid, if cleared under the Tariff, shall be effective.

c. FTRs

If a Market Participant is suspended from entering into future transactions in the FTR system, such Market Participant shall retain all FTRs held by it but shall be prohibited from acquiring any additional FTRs during the course of its suspension. It is intended that any suspension under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy will occur promptly, and the definitive timing of any such suspension shall be determined by the ISO from time to time as reported to the NEPOOL Budget and Finance Subcommittee, and shall be posted on the ISO website.

d. Virtual Transactions

Notwithstanding the foregoing, if a Market Participant is suspended in accordance with the provisions of the ISO New England Financial Assurance Policy as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant and, but for such Increment Offers and/or Decrement Bids, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, then such suspension shall be limited to (i) the immediate "last in, first out" rejection of pending individual uncleared Increment Offers and Decrement Bids submitted by that Market Participant (it being understood that Increment Offers and Decrement Bids are batched by the ISO in accordance with the time, and that Increment Offers and Decrement Bids will be rejected by the batch); and (ii) the suspension of that Market Participant's ability to submit additional Increment Offers and Decrement Bids unless and until it has complied with the ISO New England Financial Assurance Policy, and the determination of compliance for these purposes will take into account the level of aggregate outstanding obligations of that Market Participant after giving effect to the immediate rejection of that Market Participant's Increment Offers and Decrement Bids described in clause (i).

e. Bilateral Transactions

If the sum of the financial assurance and credit limits of a Market Participant that has financial assurance requirements equals zero and that Market Participant would be in compliance with the ISO New England Financial Assurance Policy but for the submission of bilateral transactions to the ISO to which the Market Participant is a party, or if a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent as a result of one or more bilateral transactions submitted to the ISO to which the Market Participant is a party, then the consequences described in subsection (a) above shall be limited to: (i) rejection of any pending bilateral transactions to which a Market Participant is a party that cause the Market Participant to incur a financial obligation in the ISO's settlement system or any

liability to the ISO, NEPOOL, or the Market Participants, such that the aggregate value of the pending bilateral transactions submitted by all Market Participants is maximized (recognizing the downstream effect that rejection of a bilateral transaction may have on the Market Credit Test Percentages, FTR Credit Test Percentages, or Transmission Credit Test Percentages of other Market Participants), while ensuring that the financial assurance requirements of each Market Participant are satisfied; and (ii) suspension of that Market Participant's ability to submit additional bilateral transactions until it has complied with the ISO New England Financial Assurance Policy (the determination of compliance for these purposes will take into account the level of aggregate outstanding obligations of the Market Participant after giving effect to the immediate rejection of the bilateral transactions to which the Market Participant is a party as described in clause (i) above). In the case of a bilateral transaction associated with the Day-Ahead Energy Market, the ISO will provide notice to a Market Participant that would be in default of the ISO New England Financial Assurance Policy as a result of the bilateral transaction, and the consequences described in clauses (i) and (ii) above shall only apply if the Market Participant fails to cure its default by 6:00 p.m. Eastern Time of that same Business Day. In the case of a Capacity Load Obligation Bilateral, the consequences described in clauses (i) and (ii) above shall apply if the Market Participant does not cure its default within one Business Day after notification that a Capacity Load Obligation Bilateral caused the default. Bilateral transactions that transfer Forward Reserve Obligations and Supplemental Availability Bilaterals are not subject to the provisions of this Section III.B.3(e).

4. Serial Notice and Suspension Penalties

If either (x) a Market Participant is suspended from the New England Markets because of a failure to satisfy its Financial Assurance Requirements in accordance with the provisions of the ISO New England Financial Assurance Policy or (y) a Market Participant receives more than five notices that its Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage has exceeded 100 percent (100%) in any rolling 365-day period, then such Market Participant shall pay a $1,000 penalty for such suspension and for each notice after the fifth notice in a rolling 365-day period. If a Market Participant receives a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage has exceeded 100 percent (100%) in the same day, then only one of those notices will count towards the

five notice limit. All penalties paid under this paragraph shall be deposited in the Late Payment Account maintained under the ISO New England Billing Policy.

C. Additional Financial Assurance Requirements for Certain Municipal Market Participants

Notwithstanding the other provisions of the ISO New England Financial Assurance Policy and in addition to the other obligations hereunder, a Credit Qualifying Municipal Market Participant that is not a municipality (which, for purposes of this Section III.C, does not include an agency or subdivision of a municipality) must provide additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation, unless either: (1) that Credit Qualifying Municipal Market Participant has a corporate Investment Grade Rating from one or more of the Rating Agencies; or (2) that Credit Qualifying Municipal Market Participant has an Investment Grade Rating from one or more of the Rating Agencies for all of its rated indebtedness; or (3) that Credit Qualifying Municipal Market Participant provides the ISO with an opinion of counsel that is acceptable to the ISO confirming that amounts due to the ISO under the Tariff have priority over, or have equal priority with, payments due on the debt on which the Credit Qualifying Municipal Market Participant's Investment Grade Rating is based. Each legal opinion provided under clause (3) of this Section III.C will be updated no sooner than 60 days and no later than 30 days before each reconfiguration auction that precedes a Capacity Commitment Period to which such legal opinion relates, and if that update is not provided or that update is not acceptable to the ISO, the applicable Credit Qualifying Municipal Market Participant must either satisfy one of the other clauses of this Section III.C or provide additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation.

D. Inventoried Energy Program Financial Assurance Requirement

Notwithstanding the other provisions of the ISO New England Financial Assurance Policy and in addition to the other obligations hereunder, if any Market Participant has submitted a Forward Energy Inventory Election approved by the ISO under Section III.K.1.1 of the Tariff, such Market Participant shall be subject to the additional financial assurance requirements of this section. Any such Market Participant must provide additional financial assurance in one of the forms described in Section X below in an

amount equal to the Inventoried Energy Program Financial Assurance Requirement on or before December 1 of each program year. The Inventoried Energy Program Financial Assurance Requirement will be calculated on a daily basis for each program year, from December 1, 2023 through February 29, 2024 and separately from December 1, 2024 through February 28, 2025, as follows:

IEP Financial Assurance Requirement = MAX(0, FE_MWh - Q_MWh) * D_95 * MF * SPR

Where:

FE_MWh = is the amount of Forward Energy Inventory elected by the Market Participant;

Q_MWh = is the maximum observed physical inventory over the prior 15 days;

D_95 = is the 95th percentile of observed Inventoried Energy Days, which for the 2023-2024 and 2024-2025 program years shall be 19;

MF = is the month factor, which shall be 100% for December, 87% for January, and 26% for February; and

SPR = spot payment rate = the $/MWh rate used in the calculation of Inventoried Energy Spot Payments as described in Section III.K.3.2 of the Tariff.

IV. CERTAIN NEW AND RETURNING MARKET PARTICIPANTS REQUIREMENTS

A new Market Participant or a Market Participant other than an FTR-Only Customer, or a Governance Only Member whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months (a "Returning Market Participant") is required to provide the ISO, for three months in the case of a new Market Participant and six months in the case of a Returning Market Participant, financial assurance in one of the forms described in Section X below equal to any amount of additional financial assurance required to meet the capitalization requirements described in Section II.A.4 plus the greater of (a) its Financial Assurance Requirement or (b) its "Initial Market Participant Financial Assurance Requirement." A new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement must be provided to the ISO no later than one Business Day before commencing activity in the New England Markets or commencing transmission service under the Tariff, and shall be determined by the following formula:

$$FAR = G + T + L + E$$

Where FAR is the Initial Market Participant Financial Assurance Requirement and G, T, L and E are determined by the following formulas:

$G = (MW_g \times Hr_{DA} \times D \times 3.25) + (MW_g \times Hr_{MIS} \times S_2 \times 3.25)$;

Where:

MW_g = Total nameplate capacity of the Market Participant's generation units that have achieved commercial operation;

Hr_{DA} = The number of hours of generation that any such generation unit could be bid in the Day-Ahead Energy Market before it could be removed if such unit tripped, as determined by the ISO in its sole discretion;

D = The maximum observed differential between Energy prices in the Day-Ahead and Real-Time Energy Markets during the prior calendar year ("Maximum Energy Price Differential"), as determined by the ISO in its sole discretion;

Hr_{MIS} = The standard number of hours between generation and the issuance of initial Market Information Server ("MIS") settlement reports including projected generation activity for such units, as determined by the ISO in its sole discretion; and

S_2 = The per MW amount assessed pursuant to Schedule 2 of Section IV.A of this Tariff, as determined by the ISO.

T = $MW_t \times Hr_{MIS} \times (D + S_{2\text{-}3}) \times 3.25$;

Where: MW_t = Number of MWs to be traded in the New England Markets as reasonably projected by the new Market Participant or the Returning Market Participant;

Hr_{MIS} = The standard number of hours between generation and the issuance of initial MIS settlement reports including projected generation activity, as determined by the ISO in its sole discretion;

D = Maximum Energy Price Differential; and

$S_{2\text{-}3}$ = The per MWh amount assessed pursuant to Schedules 2 and 3 of Section IV.A of the Tariff, as determined annually by the ISO.

$$L = (MW_1 \times LF \times Hr_{MIS} \times (EP + S_{2\text{-}3}) \times 3.25) + (MW_1 \times Hr_{MIS} \times TC \times 3.25)$$

Where:

MW_1 = MWs of Real-Time Load Obligation (as defined in Market Rule 1) of the new Market Participant or Returning Market Participant;

LF = Average load factor in New England, as determined annually by the ISO in its sole discretion;

Hr_{MIS} = The standard number of hours between generation and the issuance of initial MIS settlement reports including projected generation activity, as determined by the ISO in its sole discretion;

EP = The average price of Energy in the Day-Ahead Energy Market for the most recent calendar year for which information is available from the Annual Reports published by the ISO, as determined by the ISO in its sole discretion;

$S_{2\text{-}3}$ = The per MW amount assessed pursuant to Schedules 2 and 3 of Section IV.A of the Tariff, as determined annually by the ISO; and

TC = The hourly transmission charges per MW_1 assessed under the Tariff (other than Schedules 1, 8 and 9 of Section II of the Tariff), as determined annually by the ISO.

$$E = (SE) \times 3.25$$

Where:

SE = Average monthly share of Participant Expenses for the applicable Sector.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV is 80 percent or more of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equaled or exceeded 80 percent (80%) under Section III.B above.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV is 90 percent or more of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equaled or exceeded 90 percent (90%) under Section III.B above.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV exceeds 100 percent of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeded 100 percent (100%) under Section III.B above.

V. NON-MARKET PARTICIPANT TRANSMISSION CUSTOMERS REQUIREMENTS

A. Ongoing Financial Review and Credit Ratings

1. Rated Non-Market Participant Transmission Customer and Transmission Customers

Each Rated Non-Market Participant Transmission Customer that does not currently have an Investment Grade Rating must provide an appropriate form of financial assurance as described in Section X below.

2. Unrated Non-Market Participant Transmission Customers

Any Unrated Non-Market Participant Transmission Customer that (i) has defaulted on any of its obligations under the Tariff (including without limitation its obligations hereunder and under the ISO New England Billing Policy) during the immediately preceding 365-day period; or (ii) does not have a Current Ratio of at least 1.0, a Debt-to-Total Capitalization Ratio of 0.6 or less, and an EBITDA-to-Interest Expense Ratio of at least 2.0 must provide an appropriate form of financial assurance as described in Section X below. An Unrated Non-Market Participant Transmission Customer that does not meet either of the conditions described in clauses (i) and (ii) of this paragraph is referred to herein as satisfying the "NMPTC Credit Threshold."

B. NMPTC Credit Limits

1. NMPTC Market Credit Limit

A Market Credit Limit shall be established for each Non-Market Participant Transmission Customer as set forth in this Section V.B.1.

The Market Credit Limit of each Rated Non-Market Participant Transmission Customer shall at any time be equal to the least of: (i) the applicable percentage of such Rated Non-Market Participant Transmission Customer's Tangible Net Worth (as reflected in the following table); (ii) $50 million; or (iii) 20 percent (20%) of TADO:

Investment Grade Rating		**Percentage of Tangible Net Worth**
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%
AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%

A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

The Market Credit Limit of each Unrated Non-Market Participant Transmission Customer that satisfies the NMPTC Credit Threshold shall at any time be equal to the least of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Market Participant Transmission Customer's Tangible Net Worth, (ii) $25 million or (iii) 20 percent (20%) of TADO. The Market Credit Limit of each Unrated Non-Market Participant Transmission Customer that does not satisfy the NMPTC Credit Threshold shall be $0.

2. NMPTC Transmission Credit Limit

A Transmission Credit Limit shall be established for each Non-Market Participant Transmission Customer in accordance with this Section V.B.2.

The Transmission Credit Limit of each Rated Non-Market Participant Transmission Customer shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Market Participant Transmission Customer's Tangible Net Worth as listed in the following table or (ii) $50 million:

Investment Grade Rating		**Percentage of Tangible Net Worth**
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%
AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%
A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%

BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

The Transmission Credit Limit of each Unrated Non-Market Participant Transmission Customer that satisfies the NMPTC Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Market Participant Transmission Customer's Tangible Net Worth or (ii) $25 million. The Transmission Credit Limit of each Unrated Non-Market Participant Transmission Customer that does not satisfy the NMPTC Credit Threshold shall be $0.

3. NMPTC Total Credit Limit

The sum of a Non-Market Participant Transmission Customer's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change, each Rated Non-Market Participant Transmission Customer that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the amount set forth in Section V.B.1 above) and its Transmission Credit Limit (up to the amount set forth in Section V.B.2 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Market Participant Transmission Customer may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Market Participant Transmission Customer does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates. If the sum of the amounts for Affiliates is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate, or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

C. Information Reporting Requirements for Non-Market Participant Transmission Customers

Each Rated Non-Market Participant Transmission Customer having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis, within 10 days of their becoming available and within 65 days after the end of the applicable fiscal quarter of such Rated Non-Market Participant Transmission Customer, its balance sheet, which shall show sufficient detail for the ISO to assess the Rated Non-Market Participant Transmission Customer's Tangible Net Worth. In addition, each Rated Non-Market Participant Transmission Customer that has an Investment Grade Rating having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of their becoming available and within 120 days after the end of the fiscal year of such Rated Non-Market Participant Transmission Customer, balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). If any of this financial information is available on the internet, the Rated Non-Market Participant Transmission Customer may provide instead a letter to the ISO stating where such information may be located and retrieved.

Each Unrated Non-Market Participant Transmission Customer having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis, within 10 days of their becoming available and within 65 days after the end of the applicable fiscal quarter of such Unrated Non-Market Participant Transmission Customer, its balance sheet, which shall show sufficient detail for the ISO to assess the Unrated Non-Market Participant Transmission Customer's Tangible Net Worth. Unrated Non-Market Participant Transmission Customers having a Market Credit Limit or Transmission Credit Limit greater than $0 shall also provide additional financial statements, which shall show

sufficient detail for the ISO to calculate such Unrated Non-Market Participant Transmission Customer's Current Ratio, Debt-to-Total Capitalization Ratio and EBITDA-to-Interest Expense Ratio. In addition, each such Unrated Non-Market Participant Transmission Customer that satisfies the Credit Threshold and has a Market Credit Limit or Transmission Credit Limit of greater than $0 or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of becoming available and within 120 days after the end of the fiscal year of such Unrated Non-Market Participant Transmission Customer balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). Where any of the above financial information is available on the internet, the Unrated Non-Market Participant Transmission Customer may provide the ISO with a letter stating where such information may be located and retrieved.

If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-along subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; (iii) compiled statements; (iv) internally prepared statements; or (v) tax returns).

Except in the case of a Non-Market Participant Transmission Customer that submits audited financial statements to the ISO, financial statements submitted to the ISO pursuant to this Section V.C shall be accompanied by a written statement from a Senior Officer of the Non-Market Participant Transmission Customer certifying the accuracy of those financial statements. If an attestation was made by an independent accounting firm, then the written statement shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required.

Notwithstanding any other provision in this subsection, the ISO may require any Non-Market Participant Transmission Customer to submit the financial statements and other information described in this subsection. The Non-Market Participant Transmission Customer shall provide the requested statements and other information within 10 days of such request. If a Non-Market Participant Transmission Customer fails to provide financial statements or other information as requested and the ISO determines that the Non-Market Participant Transmission Customer poses an unreasonable risk to the New England Markets, then the ISO may request that the Non-Market Participant Transmission Customer provide additional financial assurance in an amount no greater than $10 million, or take other measures to substantiate the Non-Market Participant Transmission Customer's ability to safely transact in the New England Markets (any additional financial assurance provided pursuant to this Section V.C shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy). If the Non-Market Participant Transmission Customer fails to comply with such a request from the ISO, then the ISO may issue a notice of suspension or termination to the Non-Market Participant Transmission Customer. If the Non-Market Participant Transmission Customer fails to comply with the ISO's request within 5 Business Days from the date of issuance of the notice of suspension or termination, then the ISO may suspend or terminate the Non-Market Participant Transmission Customer.

A Non-Market Participant Transmission Customer may choose not to submit financial statements as described in this Section V.C, in which case the ISO shall use a value of $0.00 for the Non-Market Participant Transmission Customer's total assets and Tangible Net Worth for purposes of the capitalization assessment described in Section II.A.4(a) and such Non-Market Participant Transmission Customer's Market Credit Limit and Transmission Credit Limit shall be $0.00.

A Non-Market Participant Transmission Customer may choose to provide additional financial assurance in an amount equal to $10 million in lieu of providing financial statements under this Section V.C. Such amount shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy but shall be sufficient to meet the capitalization requirements in Section II.A.4(a)(iii).

D. Financial Assurance Requirement for Non-Market Participant Transmission Customers

Each Non-Market Participant Transmission Customer that provides additional financial assurance pursuant to the ISO New England Financial Assurance Policy must provide the ISO with financial assurance in one of the forms described in Section X below and in the amount described in this Section V.D (the "NMPTC Financial Assurance Requirement").

1. Financial Assurance for ISO Charges

Each Non-Market Participant Transmission Customer must provide the ISO with additional financial assurance such that the sum of its Market Credit Limit and that additional financial assurance shall at all times be at least equal to the sum of:

(i) two and one-half (2.5) times the average monthly Non-Hourly Charges for such Non-Market Participant Transmission Customer over the two most recently invoiced calendar months (which amount shall not in any event be less than $0); plus

(ii) amount of any unresolved Disputed Amounts received by such Non-Market Participant Transmission Customer.

2. Financial Assurance for Transmission Charges

Each Non-Market Participant Transmission Customer must provide the ISO with additional financial assurance hereunder such that the sum of (x) its Transmission Credit Limit and (y) the excess of (A) the available amount of the additional financial assurance provided by that Non-Market Participant Transmission Customer over (B) the amount of that additional financial assurance needed to satisfy the requirements of Section V.D.1 above is equal to two and one-half (2.5) times the average monthly Transmission Charges for such Non-Market Participant Transmission Customer over the two most recently invoiced calendar months (which amount shall not in any event be less than $0)

3. Notice of Failure to Satisfy NMPTC Financial Assurance Requirement

A Non-Market Participant Transmission Customer that knows or can reasonably be expected to know that it is not satisfying its NMPTC Financial Assurance Requirement shall notify the ISO immediately of that fact. Without limiting the availability of any other remedy or right hereunder, failure by any Non-Market Participant Transmission

Customer to comply with the provisions of the ISO New England Financial Assurance Policy (including failure to satisfy its NMPTC Financial Assurance Requirement) may result in the commencement of termination of service proceedings against that non-complying Non-Market Participant Transmission Customer.

VI. ADDITIONAL PROVISIONS FOR FTR TRANSACTIONS

Market Participants must complete an ISO-prescribed training course prior to participating in the FTR Auction. All Market Participants transacting in the FTR Auction that are otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy, including all FTR-Only Customers ("Designated FTR Participants") are required to provide financial assurance in an amount equal to the sum of the FTR Settlement Risk Financial Assurance, the Unsettled FTR Financial Assurance, and the Settlement Financial Assurance, each as described in this Section VI (such sum being referred to in the ISO New England Financial Assurance Policy as the "FTR Financial Assurance Requirements").

A. FTR Settlement Risk Financial Assurance

A Designated FTR Participant is required to provide "FTR Settlement Risk Financial Assurance" for each bid it submits into an FTR Auction and for each FTR that is awarded to it in an FTR Auction, as described below.

After bids are finalized for an FTR Auction, but before the auction results are final, a Designated FTR Participant must provide FTR Settlement Risk Financial Assurance based on its bids for each FTR path. The ISO will calculate an FTR Settlement Risk Financial Assurance amount for each direction (prevailing flow and counter flow) of each FTR path on which the Designated FTR Participant has bid, equal to the total number of MW bid for that direction of the FTR path multiplied by the applicable proxy value for the FTR path (as described below) multiplied by the number of hours associated with the bid. For that FTR path, the Designated FTR Participant must provide FTR Settlement Risk Financial Assurance equal to the higher of the amounts calculated for each direction.

Once an FTR Auction's results are final, a Designated FTR Participant must provide FTR Settlement Risk Financial Assurance based on awarded FTRs, equal to the MW value of each awarded FTR multiplied by the applicable proxy value for the FTR path (as described below) multiplied by the number of hours associated with the FTR. For

purposes of this calculation, the ISO will net the MW values of a Designated FTR Participant's awarded FTRs having the same or opposite path, same contract month, and same type (on-peak or off-peak). For purposes of this netting, annual FTRs may be converted into monthly positions.

The proxy value for each FTR path, which shall be calculated separately for on-peak and off-peak FTRs, will be based on the standard deviation observed in the difference between the average congestion components of the Locational Marginal Price in the Day-Ahead Energy Market at the path's sink and source for the previous 36 months, with differing multipliers for annual and monthly FTRs and for prevailing flow and counter flow paths. These multipliers will be reviewed and approved by the NEPOOL Budget and Finance Subcommittee and shall be posted on the ISO's website. Where there is insufficient data to perform these calculations for a node, zonal data will be used instead.

FTR Settlement Risk Financial Assurance will be adjusted as the awarded FTRs are settled. In no event will the FTR Settlement Risk Financial Assurance be less than $0.

B. Unsettled FTR Financial Assurance

A Designated FTR Participant is required to maintain, at all times, "Unsettled FTR Financial Assurance" for all FTRs awarded to it in any FTR Auctions. Immediately after FTRs are awarded in an FTR Auction, the Unsettled FTR Financial Assurance for those FTRs shall be zero. After subsequent FTR Auctions, the Unsettled FTR Financial Assurance for each FTR awarded in a previous FTR Auction shall be adjusted to reflect any change in the clearing price for that FTR based on non-zero volume. The adjustment will be equal to the change in the clearing price multiplied by the number of MW of the previously awarded FTR, with increases in the clearing price reducing the Unsettled FTR Financial Assurance amount and decreases in the clearing price increasing the Unsettled FTR Financial Assurance amount. For purposes of these calculations, the ISO will consider FTRs having the same or opposite path, same contract month, and same type (on-peak or off-peak) together. A Designated FTR Participant's Unsettled FTR Financial Assurance may be a charge or a credit, and in the case of a credit, may offset the Designated FTR Participant's other FTR Financial Assurance Requirements (but not to less than zero). A Designated FTR Participant's Unsettled FTR Financial Assurance will be adjusted as the awarded FTRs are settled.

C. Settlement Financial Assurance

A Designated FTR Participant that has been awarded a bid in an FTR Auction is required to provide "Settlement Financial Assurance." The amount of a Designated FTR Participant's Settlement Financial Assurance shall be equal to the amount of any settled but uninvoiced Charges incurred by such Designated FTR Participant for FTR transactions less the settled but uninvoiced amounts due to such Market Participant for FTR transactions. These amounts shall include the costs of acquiring FTRs as well as payments and charges associated with FTR settlement. Additionally, when the Designated FTR Participant is invoiced and the net of the charges incurred by such Designated FTR Participant for FTR transactions and the amount due to such Market Participant for FTR transactions results in a net charge, the amount of the net charge shall be added to the Designated FTR Participant's Settlement Financial Assurance until the invoice is paid.

D. Consequences of Failure to Satisfy FTR Financial Assurance Requirements

If a Designated FTR Participant does not have additional financial assurance equal to its FTR Financial Assurance Requirements (in addition to its other financial assurance obligations hereunder) in place at the time an FTR Auction into which it has bid closes, then, in addition to the other consequences described in the ISO New England Financial Assurance Policy, all bids submitted by that Designated FTR Participant for that FTR Auction will be rejected. The Designated FTR Participant will be allowed to participate in the next FTR Auction held provided it meets all requirements for such participation, including without limitation those set forth herein. Each Designated FTR Participant must maintain the requisite additional financial assurance equal to its FTR Financial Assurance Requirements for the duration of the FTRs awarded to it. The amount of any additional financial assurance provided by a Designated FTR Participant in connection with an unsuccessful bid in an FTR Auction which, as a result of such bid being unsuccessful, is in excess of its FTR Financial Assurance Requirements will be held by the ISO and will be applied against future FTR bids by and awards to that Designated FTR Participant unless that Designated FTR Participant requests in writing to have such excess financial assurance returned to it. Prior to returning any financial assurance to a Designated FTR Participant, the ISO shall use such financial assurance to satisfy any overdue obligations of that Designated FTR Participant. The ISO shall only return to that

Designated FTR Participant the balance of such financial assurance after all such overdue obligations have been satisfied.

VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS

Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Forward Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy, and any Market Participant with System-Backed Export transactions (each a "Designated FCM Participant"), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the "FCM Financial Assurance Requirements"). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant.

A. FCM Delivery Financial Assurance

Each Designated FCM Participant that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter, shall be subject to a "Corporate Liquidity Assessment" as described in this Section VII.A to determine its FCM Delivery Financial Assurance.

1. FCM Delivery Financial Assurance Calculation

A Designated FCM Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy. If a Designated FCM Participant's FCM Delivery Financial Assurance is negative, it will be used to reduce the Designated FCM Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements), but not to less than zero.

FCM Delivery Financial Assurance is calculated according to the following formula for a Designated FCM Participant that has a Capacity Supply Obligation up to and including the end of the Capacity Commitment Period associated with the fifteenth Forward Capacity Auction:

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC

FCM Delivery Financial Assurance is calculated according to the following applicable formula for a Designated FCM Participant that has a Capacity Supply Obligation commencing at the beginning of the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction and every Capacity Commitment Period thereafter. The applicable FCM Delivery Financial Assurance formula is determined by the results of a Corporate Liquidity Assessment and is limited by the operation of the applicable stop-loss mechanisms as set forth in Market Rule 1 (including those that may apply in the next Capacity Commitment Period).

Corporate Liquidity Assessment Result: Low Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC

Corporate Liquidity Assessment Result: Medium Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC – Peak Monthly Stop-loss x max[(ABR – CWAP), 0.1]

Corporate Liquidity Assessment Result: High Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC – Peak Monthly Stop-loss x max[(ABR – CWAP), 0.1] – Second Largest Monthly Stop-loss x max[(ABR – CWAP), 0.1]

Where:

MCC (monthly capacity charge) equals monthly capacity payments incurred in previous months, which have not yet been invoiced in instances where the MCC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MCC is a charge to the Designated FCM Participant. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

IMC (intra-month collateral) equals estimated monthly capacity payments incurred during the current delivery month as limited by the difference (which shall in no event be less than zero) between (A) the minimum of the applicable monthly stop-loss and the remaining annual stop-loss as described in Section III.13.7.3.1 and Section III.13.7.3.2 of Market Rule 1, respectively, and (B) the amount of additional FCM Delivery Financial Assurance when considering the Designated FCM Participant's current month FCM Delivery Financial Assurance obligation as compared to the Designated FCM Participant's next month FCM Delivery Financial Assurance obligation, in each case without giving effect to the IMC and MCC variables when calculating such additional amount. Where the estimated monthly capacity payments for each Designated FCM Participant, shall be updated three (3) days after publication of the most recent FCM Preliminary Capacity Performance Score report (or equivalent report) on the Market Information Server.

DFAMW (delivery financial assurance MW) equals the sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. If the calculated DFAMW is less than zero, then the DFAMW will be set equal to zero.

PE (potential exposure) is a monthly value calculated for the Designated FCM Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. The Forward Capacity Auction Starting Price shall correspond to that used in the Forward Capacity Auction corresponding to the current Capacity Commitment Period and the capacity prices shall correspond to those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month.

In the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7 of Market Rule 1, the Forward

Capacity Auction Starting Price shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) in the above calculation until the multi-year election period expires.

ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. For the purpose of calculating the ABR, all Capacity Balancing Ratios, including Capacity Balancing Ratios for Capacity Scarcity Conditions that occurred in past Capacity Commitment Periods or in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, shall be calculated utilizing the Capacity Balancing Ratio formula that is currently effective, as described in Section III.13.7.2.3 or Section III.15.8.2.3 of Market Rule 1. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60.

CWAP (capacity weighted average performance) is the capacity weighted average performance of the Designated FCM Participant's portfolio. For each resource in the Designated FCM Participant's portfolio, excluding any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1, and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource's Capacity Supply Obligation shall be multiplied by the average performance of the resource. The CWAP shall be the sum of all such values, divided by the Designated FCM Participant's DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

The average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months

in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary average performance for gas-fired steam generating resources, combined-cycle combustion turbines and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating resources shall equal 0.85; the temporary average performance for oil-fired steam generating resources shall equal 0.65; the temporary average performance for all other resources shall equal 1.00. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

SF (scaling factor) is a month-specific multiplier, as follows:

June and December	2.000;
July and January	1.732;
August and February	1.414;
All other months	1.000.

Peak Monthly Stop-loss equals the largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

Second Largest Monthly Stop-loss equals the second largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

2. Corporate Liquidity Assessment Methodology

The ISO will perform a "Corporate Liquidity Assessment" to determine the appropriate liquidity risk assessment category for each Designated FCM Participant (i.e., low risk,

medium risk, or high risk) that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter.

(a) For each Designated FCM Participant, the Corporate Liquidity Assessment shall be performed as follows:
- When the Available Corporate Liquidity is greater than or equal to the sum of the three largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered low risk;
- When the Available Corporate Liquidity is less than the sum of the three largest but greater than or equal to the sum of the two largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered medium risk; and
- When the Available Corporate Liquidity is less than the sum of the two largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered high risk.

(b) For Designated FCM Participants that have provided a guaranty (in accordance with this Section VII.A) from the same Affiliate, or for Designated FCM Participants that are also providing a guaranty (in accordance with this Section VII.A) for an Affiliate:
- The respective Designated FCM Participants will be assessed as a whole and will be collectively assigned one Corporate Liquidity Assessment result (i.e., low risk, medium risk, or high risk);
- When the Available Corporate Liquidity is greater than or equal to the sum of the three largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered low risk;
- When the Available Corporate Liquidity is less than the sum of the three largest aggregated Applicable Monthly Stop-losses but is greater than or equal to the sum of two largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered medium risk; and

- When the Available Corporate Liquidity is less than the sum of the two largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered high risk.

(c) For Designated FCM Participants that have provided a guaranty (in accordance with this Section VII.A) from multiple Affiliates:

- The guarantors' financial statements will be considered on an aggregate basis for purposes of the Available Corporate Liquidity calculation taking into account other guaranties provided by any such guarantor under this Section VII.A.

Where:

Calculation Period is the current delivery month through the following five consecutive months.

The Applicable Monthly Stop-loss equals the sum of the monthly stop-losses for each resource in a Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1 for the corresponding months within the Calculation Period.

Available Corporate Liquidity is the sum of unrestricted cash and cash equivalents; marketable securities and money market instruments; undrawn committed credit facilities not expiring within three months of the date of the applicable financial statements; and excess financial assurance. Other than with respect to excess financial assurance, such values shall be (a) as reflected on the most recent financial statements provided by the Designated FCM Participant, provided that such financial statements were provided for the most recently completed financial reporting period and compliant with the requirements of this Section VII.A, and (b) calculated in accordance with international accounting standards or generally accepted accounting principles in the United States at the time of determination consistently applied. Excess financial assurance shall be calculated as any financial assurance (in an acceptable form in accordance with Section X) provided by the Designated FCM Participant covering its FCM Delivery Financial Assurance obligations plus any financial assurance (in an acceptable form in accordance with Section X) provided by the Designated FCM Participant in excess of its total

Financial Assurance Obligations, each as reflected in the ISO's Financial Assurance Management (FAM) or equivalent system.

For the avoidance of doubt, the components of the Available Corporate Liquidity calculation that are derived from financial statements shall be based on the financial statements of the Designated FCM Participant unless it provides an Affiliate guaranty in compliance with this Section VII.A, in which case the values shall be based on the financial statements of the entity(ies) providing the guaranty. If an acceptable Affiliate guaranty is provided, stop-loss and excess financial assurance values will still be based on the Designated FCM Participant.

Each Designated FCM Participant shall submit to the ISO, on a quarterly basis, its (or its guarantor's, as applicable) audited or unaudited balance sheet or equivalent financial statements, which shall show sufficient detail for the ISO to assess the Designated FCM Participant's (or guarantor's, as applicable) Available Corporate Liquidity. Such financial information shall be accompanied by a certificate from a Senior Officer of the Designated FCM Participant (or guarantor as applicable) that provides the relevant financial information and certifies the accuracy of the attached financial statements. If an attestation was made by an independent accounting firm, then the certificate shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required. The ISO shall post a generally acceptable "clean" form of certificate on its website. Financial statements provided on a quarterly basis shall be submitted within 10 days of such statements becoming available and within 65 days after the end of the applicable fiscal quarter.

Designated FCM Participants that are assessed as medium risk or high risk may elect to provide financial statements on a monthly basis until such a time as they are subsequently assessed as a lower risk category (e.g., from high risk to medium risk, medium risk to low risk, or high risk to low risk); provided that such election shall be for a minimum period of six continuous months during which they are continuously assessed at a lower risk category. Financial statements submitted on a monthly basis are required to be provided to the ISO within 20 days after the end of the prior month and otherwise be provided in accordance with this Section VII.A.

A Designated FCM Participant may choose not to submit financial statements as described in this Section VII.A. If a Designated FCM Participant chooses not to submit financial statements as described in this Section VII.A or if such financial statements are not compliant with the requirements described in this Section VII.A, the ISO shall use a value of $0.00 for Available Corporate Liquidity values derived from financial statements until such time as compliant financial statements are provided.

The ISO shall review the information provided pursuant to this Section VII.A on a rolling basis and will calculate the Available Corporate Liquidity within a reasonable time period which shall not exceed 30 Business Days from the date of receipt.

3. FCM Affiliate Guaranties

For the purposes of the Corporate Liquidity Assessment, a Designated FCM Participant may provide an unconditional, irrevocable guaranty from an Affiliate to the ISO guaranteeing the payment of all Capacity Performance Payments owed by the Designated FCM Participant. Upon the ISO's acceptance of an Affiliate guaranty, the guarantor(s) must provide financial statements in accordance with this Section VII.A, and the Corporate Liquidity Assessment will be performed based on the financial information of the guarantor(s). The ISO will post a generally acceptable sample "clean" guaranty on its website, and all guaranties provided pursuant to this Section VII.A shall be in such form with only non-material changes (as determined by the ISO in its sole discretion). The ISO in its sole discretion may update the form guaranty from time to time. The ISO has the right to draw upon the guaranty in the event of a default under the ISO New England Billing Policy up to any amount owed for unpaid Capacity Performance Payments. At any time, the ISO may in its sole discretion provide notice to a Designated FCM Participant that it is choosing to reject or terminate its Affiliate guaranty because such guaranty presents unreasonable risk to the ISO or the New England Markets. In the case of a termination (or planned termination), upon the ISO providing such notice the guaranty shall not be considered for purposes of such Designated FCM Participant's Corporate Liquidity Assessment beginning at 8:30 a.m. on the next Business Day, provided that the ISO may, in its sole discretion, extend this period by up to twenty (20) Business Days. For the avoidance of doubt, notice from the ISO to the Designated FCM Participant that the guaranty its Affiliate provided is being terminated (or will be

terminated), does not constitute a termination notice under such guaranty and the ISO, in its sole discretion, may choose when to send the applicable termination notice under the terms of such guaranty.

In the ISO's sole discretion, a Designated FCM Participant may provide an unconditional, irrevocable guaranty from multiple Affiliates to the ISO guaranteeing the payment of all Capacity Performance Payments owed by the Designated FCM Participant, so long as such guaranty is otherwise in accordance with this Section VII.A and the guarantors have joint and several liability under such guaranty.

B. Non-Commercial Capacity

Notwithstanding any provision of this Section VII to the contrary, a Designated FCM Participant offering Non-Commercial Capacity for a Resource that elected existing Resource treatment for the Capacity Commitment Period beginning June 1, 2010 will not be subject to the provisions of this Section VII.B with respect to that Resource (other than financial assurance obligations relating to transfers of Capacity Supply Obligations).

1. FCM Deposit

A Designated FCM Participant offering Non-Commercial Capacity into any upcoming Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day after its qualification for such auction under Market Rule 1, an amount equal to $2/kW times the Non-Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant (the "FCM Deposit").

2. Non-Commercial Capacity in Forward Capacity Auctions

a. [Reserved for Future Use]

b. Non-Commercial Capacity Participating in Forward Capacity Auctions

A Designated FCM Participant offering Non-Commercial Capacity into the Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8

a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction an amount calculated according to the following formula:

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) – FCM Deposit

Where:
NCC = the amount of Qualified Capacity that the ISO has qualified for the Designated FCM Participant for the Forward Capacity Auction minus any Commercial Capacity

NCCFCA$ = the Net CONE associated with the Forward Capacity Auction for which the NCC has qualified (adjusted as described in Section III.13.2.4).

Multiplier = one if the auction occurs within 40 months of the commencement of the Capacity Commitment Period for which the NCC has qualified; two if the auction occurs within 28 months of the commencement of the Capacity Commitment Period for which the NCC has qualified; and three if the auction begins within 16 months of the commencement of the Capacity Commitment Period for which the NCC has qualified.

FCM Deposit = $2/kW times the Non Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant

Upon completion of the Forward Capacity Auction, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated according to the following formula:

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) + NCC Trading FA

Where:
NCC = the Capacity Supply Obligation awarded to the Designated FCM Participant in the Forward Capacity Auction minus any Commercial Capacity

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the thirteenth Forward Capacity Auction, NCCFCA$ = the Capacity Clearing Price from the first run of the auction-clearing process of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded. For Capacity Supply Obligations acquired in the fourteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCCFCA$ = the Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4).

Multiplier = one beginning at 8 a.m. (Eastern Time) on the first Business Day occurring within 40 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded; two beginning at 8 a.m. (Eastern Time) on the first Business Day occurring within 28 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded; and three beginning at 8 a.m. (Eastern Time) on the first Business Day occurring within 16 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded.

In the case of Non-Commercial Capacity that fails to become commercial by the commencement of the Capacity Commitment Period associated with the Forward Capacity Auction in which it was awarded a Capacity Supply Obligation, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated as follows: beginning at 8 a.m. (Eastern Time) on the first Business Day of the second month of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded, the Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall be four. The Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall increase by one every six months thereafter until the Non-Commercial Capacity becomes commercial or the Capacity Supply Obligation is terminated.

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the twelfth Forward Capacity Auction, NCC Trading FA = zero. For Capacity Supply Obligations acquired in the thirteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCC Trading FA shall be zero until the start of the

applicable Capacity Commitment Period, at which time NCC Trading FA shall be calculated as described below, except that in no case shall NCC Trading FA be less than zero:

(a) the total amount of NCC that has been shed (whether before or after the start of the Capacity Commitment Period) in any reconfiguration auctions or Capacity Supply Obligation Bilaterals or that is subject to a failure to cover charge pursuant to Section III.13.3.4(b) (but this total amount shall not be greater than NCC); multiplied by

(b) the difference between: (x) the weighted average price at which the Capacity Supply Obligation was acquired in the Forward Capacity Auction (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); and (y) the weighted average price or failure to cover charge rate at which the Capacity Supply Obligation was shed or assessed, as applicable, except that for monthly Capacity Supply Obligation Bilaterals, one of the following prices will be used:

(i) If the Designated FCM Participant does not certify to the ISO that it has not entered into any contract or other transaction with another party regarding the pricing of such Capacity Supply Obligation Bilateral (other than those to be settled by the ISO) that has the effect of deflating its NCC Trading FA, then the lower of: (1) the applicable monthly reconfiguration auction price, and (2) the Capacity Supply Obligation Bilateral price shall be used;

(ii) If the Designated FCM Participant provides the certification described in subsection (i) above, is the Capacity Transferring Resource, and is an Affiliate of the Capacity Acquiring Resource, then the lower of: (1) the Capacity Supply Obligation Bilateral price, and (2) the applicable Capacity Clearing Price (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs) shall be used; or

(iii) If neither subsection (i) nor (ii) applies, then the Capacity Supply Obligation Bilateral price shall be used.

plus

(c) the quantity of any Annual Reconfiguration Transactions associated with NCC for the relevant Capacity Commitment Period in which the Designated

FCM Participant is the Capacity Transferring Resource (but this amount shall not be greater than NCC) multiplied by the difference between: (x) the applicable annual reconfiguration auction clearing price, and (y) the transaction price, which shall equal one of the following:

(i) If the Designated FCM Participant does not certify to the ISO that it has not entered into any contract or other transaction with another party regarding the pricing of such Annual Reconfiguration Transaction (other than those to be settled by the ISO) that has the effect of deflating its NCC Trading FA, the transaction price shall be equal to the lower of: (1) the applicable annual reconfiguration auction clearing price, and (2) the applicable Annual Reconfiguration Transaction price;

(ii) If the Designated FCM Participant provides the certification described in subsection (i) above, is the Capacity Transferring Resource, and is an Affiliate of the Capacity Acquiring Resource, then the transaction price shall be equal to the lower of: (1) the applicable Annual Reconfiguration Transaction price, and (2) the applicable Capacity Clearing Price (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); or

(iii) If neither subsection (i) nor (ii) applies, then the applicable Annual Reconfiguration Transaction price shall be used.

c. Non-Commercial Capacity Deferral

Where the Commission approves a request to defer a Capacity Supply Obligation filed pursuant to Section III.13.3.7 of Market Rule 1, the Designated FCM Participant must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) 30 days after Commission approval of the request to defer, an amount equal to the amount that would apply to a resource that has not achieved commercial operation one year after the start of a Capacity Commitment Period in which it has a Capacity Supply Obligation, as calculated pursuant to Section VII.B.2.a or Section VII.B.2.b, as applicable.

3. Return of Non-Commercial Capacity Financial Assurance

Non-Commercial Capacity cleared in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction that is declared commercial and has had its capacity rating verified by the ISO or otherwise becomes a Resource meeting the definition of Commercial Capacity, or that is declared commercial and had a part of its capacity rating verified by the ISO and the applicable Designated FCM Participant indicates no additional portions of that Resource will become commercial, that portion of the Resource shall no longer be considered Non-Commercial Capacity under the ISO New England Financial Assurance Policy and will instead become subject to the provisions of the ISO New England Financial Assurance Policy relating to Commercial Capacity; provided that in either such case, the Designated FCM Participant will need to include in the calculation of its Financial Assurance Requirement an amount attributable to any remaining Non-Commercial Capacity.

Once Non-Commercial Capacity associated with a Capacity Supply Obligation awarded in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter becomes commercial, the Non-Commercial Capacity Financial Assurance Amount for any remaining Non-Commercial Capacity shall be recalculated according to the process outlined above for Non-Commercial Capacity participating in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter.

4. Credit Test Percentage Consequences for Provisional Members

If a Provisional Member is required to provide additional financial assurance under the ISO New England Financial Assurance Policy solely in connection with (A) a supply offer of Non-Commercial Capacity into any Forward Capacity Auction and (B) its obligation to pay Participant Expenses as a Provisional Member, and that Provisional Member is maintaining the amount of additional financial assurance required under the ISO New England Financial Assurance Policy, then the provisions of Section III.B of the ISO New England Financial Assurance Policy relating to the consequences of that Market Participant's Market Credit Test Percentage equaling 80 percent (80%) or 90 percent (90%) shall not apply to that Provisional Member.

C. SBE Financial Assurance~~[Reserved for Future Use]~~

A Designated FCM Participant with System-Backed Export transactions, as defined in Section III.13.7.2.A and Section III.15.8.2.A of Market Rule 1, must include SBE Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy.

SBE Financial Assurance is calculated according to the following formula for a Designated FCM Participant with System-Backed Export transactions.

SBE Financial Assurance = (PPR * SBE MW * Scarcity Hours) – MEC – PMEC

Where:
PPR is the Performance Payment Rate as defined in Section III.13.7.2.5 and Section III.15.8.2.5 of Market Rule 1.

SBE MW equals the Designated FCM Participant's average MW of System-Backed Exports across all Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available; provided, however, that, beginning on October 1, 2026, data from Capacity Scarcity Conditions that occurred prior to October 1, 2026 shall no longer be used once data is available from a Capacity Scarcity Condition in the relevant group of months in a prior Capacity Commitment Period or a Capacity Scarcity Condition in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.

Scarcity Hours equals the highest total number of hours in which a Capacity Scarcity Condition occurred during any month within the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.

MEC (monthly export charges) equals System-Backed Export charges incurred in previous months, which have not yet been invoiced in instances where the MEC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MEC is a charge to the Designated FCM Participant. The MEC is estimated from the first day of the current month until it is replaced by the actual settled MEC value when settlement is complete.

PMEC (preliminary export charges) equals estimated System-Backed Export charges incurred in the current month. Where the estimated System-Backed Export charges shall be updated three (3) days after publication of the applicable report on the Market Information Server.

D. Loss of Capacity and Forfeiture of Non-Commercial Capacity Financial Assurance

If a Designated FCM Participant that has acquired Capacity Supply Obligations associated with Non-Commercial Capacity is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy and does not cure such default within the appropriate cure period, or if a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy during the period between the day that is three Business Days before the FCM Deposit is required and the first day of the Forward Capacity Auction and does not cure such default within the appropriate cure period, then: (i) beginning with the first Business Day following the end of such cure period that Designated FCM Participant will be assessed a default charge of one percent (1%) of its total Non-Commercial Capacity Financial Assurance Amount at that time for each Business Day that elapses until it cures its default; and (ii) if such default is not cured by 5:00 p.m. (Eastern Time) on the sooner of (x) the fifth Business Day following the end of such cure period or (y) the second Business Day prior to the start of the next scheduled Forward Capacity Auction or annual reconfiguration auction or annual Capacity Supply Obligation Bilateral submission (such period being referred to herein as the "Non-Commercial Capacity Cure Period"), then, in addition to the other actions described in this Section VII, (A) all Capacity Supply Obligations associated with Non-Commercial Capacity that were awarded to the defaulting Designated FCM Participant in previous Forward Capacity Auctions and reconfiguration auctions and that the defaulting Designated FCM Participant acquired by

entering into Capacity Supply Obligation Bilaterals shall be terminated; (B) the defaulting Designated FCM Participant shall be precluded from acquiring any Capacity Supply Obligation that would be associated with Non-Commercial Capacity for which the defaulting Designated FCM Participant has submitted an FCM Deposit; (C) the ISO will (1) draw down the entire amount of the FCM Deposit and the Non-Commercial Capacity Financial Assurance Amount associated with the terminated Capacity Supply Obligations and (2) issue an Invoice to the Designated FCM Participant if there is a shortfall resulting from that Designated FCM Participant's failure to maintain adequate financial assurance hereunder or if the Designated FCM Participant used a Market Credit Limit to meet its FCM Financial Assurance Requirements; and (D) the default charges described in clause (i) above shall not be assessed to that Designated FCM Participant. All default charges collected under clause (i) above will be deposited in the Late Payment Account in accordance with the ISO New England Billing Policy.

If a Designated FCM Participant's Capacity Supply Obligation is terminated under Market Rule 1, the ISO will draw down the entire Non-Commercial Capacity Financial Assurance Amount provided by such Designated FCM Participant with respect to such terminated Capacity Supply Obligation. If the Designated FCM Participant has not provided enough financial assurance to cover the amount due (or that would have been due but for the Designated FCM Participant's positive Market Credit Limit) with respect to such Non-Commercial Capacity Financial Assurance Amount, then the ISO will issue an Invoice to the Designated FCM Participant for the amount due.

E. Composite FCM Transactions

For separate resources that seek to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide that capacity (collectively, a "Composite FCM Transaction"), each Designated FCM Participant participating in that Composite FCM Transaction will be responsible for providing the financial assurance required as follows:

1. the FCM Financial Assurance Requirements for each Designated FCM Participant shall be determined solely with respect to the capacity being provided, or sought to be provided, by that Designated FCM Participant;

2. [reserved];

3. if the Composite FCM Transaction involves one or more Resources seeking to provide or providing Non-Commercial Capacity, the Non-Commercial Capacity Financial Assurance Amount under Section VII.B for each Designated FCM Participant with respect to that Composite FCM Transaction will be calculated based on the commercial status of the Non-Commercial Capacity cleared through the Forward Capacity Auction;

4. any Non-Commercial Capacity Financial Assurance Amount provided under Section VII.B by each Designated FCM Participant with respect to each Resource providing Non-Commercial Capacity in the Composite FCM Transaction will be recalculated according to Section VII.B.3 as the corresponding Resource becomes commercial; and

5. in the event that the Capacity Supply Obligation is terminated, Section VII.D shall apply only to the Non-Commercial Capacity of the Designated FCM Participant participating in the Composite FCM Transaction that has failed to satisfy its obligations, and any Invoice issued thereunder will be issued only to that Designated FCM Participant.

6. the FCM Delivery Financial Assurance calculated under Section VII.A for each Designated FCM Participant contributing resources to a Composite FCM Transaction shall be based on the Capacity Supply Obligation that is provided by that Designated FCM Participant in the current month of the Capacity Commitment Period, provided that the FCM charges incurred in previous months, but not yet paid, shall increase the FCM Financial Assurance Requirements only of the Designated FCM Participant that incurred the charges.

F. Transfer of Capacity Supply Obligations

1. Transfer of Capacity Supply Obligations in Reconfiguration Auctions

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a reconfiguration auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of bidding in that reconfiguration auction, the amounts described in subsections (a) and (b) below.

(a) For the 12 month period beginning with the current month, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For purposes of this subsection (a), months in this period in which that Designated FCM Participant's net FCM revenue results in a credit are disregarded (i.e., the net credits from such months are not used to reduce the amount described in this subsection (a)) and the current month FCM charges are prorated to the proportion of remaining days in the month. The amount described in this subsection (a), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

(b) For the period including each month that is after the period described in subsection (a) above and that is included in a Capacity Commitment Period for which a Forward Capacity Auction has been conducted, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For this period, the sum of such charges may be offset by net credits from months in which the net FCM revenue results in a credit, but in no case will the amount described in this subsection (b) be less than zero. The amount described in this subsection (b), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

For purposes of these calculations, the net FCM revenue for a month shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations, demand bids and Annual Reconfiguration Transactions in the Forward Capacity Market, exclusive of any accrued Capacity Performance Payments on positions currently or previously held. Upon the completion of each reconfiguration auction, the amount to be included in the calculation of any FCM Financial Assurance Requirements of that Designated FCM Participant shall be adjusted to reflect the cleared quantities at the zonal clearing price for all activity in that reconfiguration auction and accepted Annual Reconfiguration Transactions.

2. Transfer of Capacity Supply Obligations in Capacity Supply Obligation Bilaterals

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a Capacity Supply Obligation Bilateral must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Capacity Supply Obligation Bilateral,

amounts calculated as described in Section VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Capacity Supply Obligation Bilaterals, all of those transactions will be rejected. If the Designated FCM Participant's request to transfer a Capacity Supply Obligation in a Capacity Supply Obligation Bilateral is not accepted, it will no longer include amounts related to that Capacity Supply Obligation in the calculation of its FCM Financial Assurance Requirements.

3. Financial Assurance for Annual Reconfiguration Transactions

A Designated FCM Participant that submits an Annual Reconfiguration Transaction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Annual Reconfiguration Transaction, amounts calculated as described in Section VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Annual Reconfiguration Transactions, all of those transactions will be rejected. If a transaction is rejected, the Designated FCM Participant is no longer required to include amounts related to that transaction in the calculation of its FCM Financial Assurance Requirements.

4. Substitution Auctions

A Designated FCM Participant that participates in a substitution auction must include the following charges and credits in its FCM Financial Assurance Requirements.

a. For any supply offer with at least one price-quantity pair priced less than zero must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing any price-quantity pairs priced less than zero for each month of the Capacity Commitment Period associated with the Forward Capacity Auction shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

b. A Designated FCM Participant (i) that submits a demand bid into a substitution auction for a resource that is subject to a multi-year rate pursuant to Section III.13.1.3.5.4 or Section III.13.1.1.2.2.4, (ii) for which the maximum charge that would result from clearing the capacity subject to the multi-year rate election would exceed the revenue the Designated FCM Participant will receive for the relevant Capacity Commitment Period under its multi-year rate election for the resource, (iii) must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing the capacity subject to the multi-year rate election shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

c. If a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction and does not cure such default by the earlier of (i) the end of the appropriate cure period and (ii) 5 p.m. (Eastern Time) on the second Business Day prior to the start of the Forward Capacity Auction, then the defaulting Designated FCM Participant shall be precluded from submitting a supply offer or demand bid that is subject to this Section VII.F.4.

d. Upon the completion of the substitution auction, the amount to be included in the calculation of the FCM Financial Assurance Requirements for a Designated FCM Participant as described in Section VII.F.1 above shall be adjusted to reflect all charges and credits related to the purchase or sale of Capacity Supply Obligations in the substitution auction.

VIII. [Reserved]

IX. THIRD-PARTY CREDIT PROTECTION

The ISO shall obtain third-party credit protection, in the form of credit insurance coverage ("Credit Coverage"), on terms acceptable to the ISO in its reasonable discretion at least in an amount covering

collectively the Credit Qualifying Rated Market Participants based on the formula below. Notwithstanding the foregoing, if the entity providing such Credit Coverage cannot provide the amount required by this Section IX, the ISO will reduce the required coverage for all Credit Qualifying Rated Market Participants on a pro rata basis. The total amount of the Credit Coverage shall be at least the aggregate of the following formula; provided, however, if the entity providing the Credit Coverage denies coverage (in whole or in part) for any Credit Qualifying Rated Market Participant based on its rights under the insurance policy, the ISO will use reasonable efforts to obtain documentation regarding the denial and will make reasonable efforts to appeal such denial. For each Credit Qualifying Rated Market Participant, the portion of the Credit Coverage shall be the lesser of: (A) the sum of (x) 2.5 times the average Hourly Charges for such Credit Qualifying Rated Market Participant within the previous fifty-two calendar weeks plus (y) 2.5 times the sum of the average Non-Hourly Charges (excluding charges or credits related to FTR transactions) and the average Transmission Charges for such Credit Qualifying Rated Market Participant within the previous twelve calendar months; or (B) $50 million. For any Credit Qualifying Rated Market Participant, the applicable amount of the Credit Coverage shall be adjusted monthly if the above formula produces a change that is either (A) 10% or greater, or (B) greater than $100,000. The Credit Coverage shall be provided by an insurance company rated "A-" or better by A.M. Best & Co. or "A" or better by S&P. The cost of the Credit Coverage obtained for each calendar year shall be allocated to all Credit Qualifying Rated Market Participants pro rata based, for each Credit Qualifying Rated Market Participant, on the average amount of the Invoices issued to that Credit Qualifying Rated Market Participant under the ISO New England Billing Policy in the preceding calendar year. Each Credit Qualifying Rated Market Participant shall provide the ISO with such information as may be reasonably necessary for the ISO to obtain the Credit Coverage at the lowest possible cost.

X. ACCEPTABLE FORMS OF FINANCIAL ASSURANCE

Provided that the requirements set forth herein are satisfied, acceptable forms of financial assurance include shares of registered or private mutual funds held in a shareholder account or a letter of credit, each in accordance with the provisions of this Section X. All costs associated with obtaining financial security and meeting the provisions of the ISO New England Financial Assurance Policy are the responsibility of the Market Participant or Non-Market Participant Transmission Customer providing that security (each a "Posting Entity").

A. Shares of Registered or Private Mutual Funds in a Shareholder Account

Shares of registered or private mutual funds in a shareholder account are an acceptable form of financial assurance provided that the Posting Entity providing such collateral (i)

completes all required documentation to open an account with the financial institution selected by the ISO, after consultation with the NEPOOL Budget and Finance Subcommittee, (ii) completes and executes a security agreement ("Security Agreement") in the form of Attachment 1 to the ISO New England Financial Assurance Policy (as may be modified pursuant to Section X.B.1) and is in compliance with the Security Agreement, and (iii) completes and executes a Control Agreement in the form posted on the ISO website (as may be modified pursuant to Section X.B.1) and is in compliance with the Control Agreement. Any material variation from the form of Security Agreement included in Attachment 1 to the ISO New England Financial Assurance Policy (other than as modified pursuant to Section X.B.1) or the form of Control Agreement (other than as modified pursuant to Section X.B.1) posted on the ISO website must be approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and, in the case of the Security Agreement, filed with the Commission. To the extent any amount of shares contained in the shareholder account is no longer required hereunder, the ISO shall return such collateral to the Posting Entity providing it within four (4) Business Days of a request to do so.

If the amount of collateral maintained in the shareholder account is below the required level (including by reason of losses on investments), the Posting Entity shall immediately replenish or increase the amount to the required level. The collateral will be held in an account maintained in the name of the Posting Entity and invested in the investment selected by that Posting Entity from a menu of investment options listed at the time on the ISO's website, which menu will be approved by the NEPOOL Budget and Finance Subcommittee, with discounts applied to the investments in certain of such options if and as determined by the NEPOOL Budget and Finance Subcommittee. If a Posting Entity does not select an investment for its collateral, that collateral will be invested in the "default" investment option selected by the ISO and approved by the NEPOOL Budget and Finance Subcommittee from time to time. Any dividends and distribution on such investment will accrue to the benefit of the Posting Entity. The ISO may sell or otherwise liquidate such investments at its discretion to meet the Posting Entity's obligations to the ISO. In no event will the ISO or NEPOOL or any NEPOOL Participant have any liability with respect to the investment of collateral under this Section X.A.

Notwithstanding the foregoing, an investment in shares of a registered fund in a shareholder account shall not be an acceptable form of financial assurance for a Posting Entity that is not a U.S. Person, as defined in Regulation S under the Securities Act of 1933, as amended, unless the financial institution selected by the ISO allows such Posting Entity to invest in the investment options listed at the time on the ISO's website or the Posting Entity is invested in the investment options listed on the ISO's website as of March 19, 2015.

B. Letter of Credit

An irrevocable standby letter of credit provides an acceptable form of financial assurance to the ISO. For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the end of the Business Day that is 30 days prior to the termination of such letter of credit. If the letter of credit amount is below the required level, the Posting Entity shall immediately replenish or increase the letter of credit amount or obtain a substitute letter of credit. The account party on a letter of credit must be either the Posting Entity whose obligations are secured by that letter of credit or an Affiliate of that Posting Entity.

1. Risk Mitigation Draws

The ISO may draw against a letter of credit for two reasons in addition to a failure to pay under the ISO New England Billing Policy: i) an expiring letter of credit has not been renewed, or ii) the issuing bank is downgraded below the minimum ratings requirement, each in accordance with the terms of the letter of credit (the "Risk Mitigation Draws"). The ISO may exercise its rights under the Risk Mitigation Draws up to the amount that a Posting Entity's financial assurance requirements are not covered by acceptable forms of financial assurance. The ISO will hold such funds as a security deposit for the satisfaction of all obligations owed to the ISO by the Posting Entity (the "Risk Mitigation Drawn Funds"). The Risk Mitigation Drawn Funds shall be considered an appropriate form of financial assurance as described in this Section X. The ISO will hold all right, title, and interest in the Risk Mitigation Drawn Funds and the Posting Entity shall have a contingent right to such funds less any amounts applied to any debts owed to the ISO (pursuant to the Tariff, including the ISO New England Billing Policy): (i) upon the termination of its Market Participant Financial Assurance Requirement in accordance with Section III of the Financial Assurance Policy, (ii) upon the Posting Entity's

provision of an alternative form of acceptable financial assurance in accordance with this Section X, or (iii) to the extent that any portion of the Risk Mitigation Drawn Funds are no longer required hereunder, upon the Posting Entity providing a written request to the ISO to return such portion of the funds (which request shall be honored within four (4) Business Days).

Upon request of the ISO, but no later than five (5) Business Days after the Risk Mitigation Draw, the Posting Entity shall execute a Security Agreement in the form of Attachment 1 to the ISO New England Financial Assurance Policy, provided that such form shall be modified to include within the definition of Collateral, funds received from a Risk Mitigation Draw, or an amendment to its existing Security Agreement in a form acceptable to the ISO in its sole discretion. Within thirty (30) days of the Risk Mitigation Draw the Posting Entity shall satisfy its obligations pursuant to the paragraph immediately below to direct the deposit of the Risk Mitigation Drawn Funds into the Posting Entity's shareholder account as described in Section X.A. Notwithstanding the prior sentence, if the Posting Entity provides written documentation to the ISO (which documentation must be to the ISO's reasonable satisfaction) of its inability to open a shareholder account as described in Section X.A, and the Posting Entity has executed a Security Agreement or an amendment to its existing Security Agreement as required above, the ISO shall continue to hold the Risk Mitigation Drawn Funds (and such amount shall continue to be considered financial assurance), subject to the Posting Entity's contingent right to such funds as described above, in a form determined by the ISO in its sole discretion, and any interest or income accrued on such funds, if applicable, shall be considered part of the Posting Entity's financial assurance.

Upon a Risk Mitigation Draw and unless the Posting Entity has either posted other appropriate financial assurance in the forms permitted by this Section X or provided written documentation of its inability to do so in accordance with the preceding paragraph, the Posting Entity shall within thirty (30) days of the Risk Mitigation Draw complete any steps required by the ISO to (a) open a shareholder account as described in Section X.A, (b) execute any necessary documentation, including any amendments to the Security Agreement and Control Agreement deemed necessary by the ISO in a form acceptable to the ISO in its sole discretion, for the ISO to deposit the Risk Mitigation Drawn Funds into the Posting Entity's shareholder account, and (c) direct the ISO to

deposit the Risk Mitigation Default Drawn Funds into that Posting Entity's shareholder account as described in Section X.A. Upon the Posting Entity's completion of the foregoing steps in (a) through (c) to the ISO's satisfaction, ISO shall deposit the Risk Mitigation Default Drawn Funds into that Posting Entity's shareholder account and the balance of the funds then on deposit in such account shall continue to be the collateral of the ISO.

The ISO may apply any funds received from a letter of credit, including the Risk Mitigation Drawn Funds held as a security deposit, to amounts owed by the Posting Entity in accordance with the ISO New England Billing Policy. If a Posting Entity fails to comply with the provisions of this Section X.B.1, then the Posting Entity will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

2. Requirements for Banks

Each bank issuing a letter of credit that serves as financial assurance must meet the requirements of this Section X.B.2. Each such bank must be on the ISO's "List of Eligible Letter of Credit Issuers" which shall be established pursuant to this Section X.B.2. The ISO will post the current List of Eligible Letter of Credit Issuers on its website, and update that List and posting no less frequently than quarterly; provided that if a change is made to the List of Eligible Letter of Credit Issuers, the ISO shall update the List and provide notice to the NEPOOL Budget & Finance Subcommittee. To be included on the List of Eligible Letter of Credit Issuers, (i) the bank must be organized under the laws of the United States or any state thereof, or be the United States branch of a foreign bank; (ii) have a minimum long-term debt rating (or, if the bank does not have a minimum long-term debt rating, than a minimum corporate rating) of "A-" by S&P, or "A3" by Moody's, or "A-" by Fitch; and (iii) be approved by the ISO in its sole discretion. In the event that a bank is rated by multiple Rating Agencies, if any applicable rating from the Rating Agencies falls below the levels listed, then a bank will not be considered to have satisfied the requirement under this paragraph. In addition, no Posting Entity may provide a letter of credit that has been issued by a bank that is an Affiliate of that Market Participant.

If a bank that is included on the List of Eligible Letter of Credit Issuers fails to satisfy the criteria set forth above or if the ISO determines in its sole discretion that despite satisfying the criteria set forth above, accepting a letter of credit from a bank on the List of Eligible Letter of Credit Issuers presents an unreasonable risk that a bank may fail to honor the terms of such letter of credit, the applicable Posting Entity will have five (5) Business Days from the date on which the ISO provides notice of such failure or removal to replace the letter of credit with a letter of credit from a bank satisfying the criteria or provide other financial assurance satisfying the requirements of the ISO New England Financial Assurance Policy. The ISO may extend that cure period to twenty (20) Business Days in its sole discretion. The ISO must promptly advise the NEPOOL Budget and Finance Subcommittee of any extension of a cure period beyond five (5) Business Days under this provision. For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the expiration of the five (5) or twenty (20) Business Day cure period, as applicable.

No letter of credit bank may issue letters of credit under the ISO New England Financial Assurance Policy in an amount exceeding either: (i) $100 million in the aggregate for any single Posting Entity; or (ii) $150 million in aggregate for a group of Posting Entities that are Affiliates. If a bank is removed from the List of Eligible Letter of Credit Issuers based on the ISO's determination that there is an unreasonable risk that a bank may fail to honor the terms of such letter of credit, the ISO in its sole discretion may reinstate eligibility, provided that the bank otherwise meets the conditions of this Section X.B.2.

The following provisions shall apply when a bank fails to honor the terms of one or more letters of credit issued by the bank in favor of the ISO: (i) if the bank fails to honor the terms of one letter of credit in a rolling seven hundred and thirty day period, then the ISO will issue a notice of such failure to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contracts for all Market Participants; (ii) if the bank fails to honor either the terms of one letter of credit twice or the terms of two letters of credit in a rolling seven hundred and thirty day period, then (A) the ISO shall issue a notice described in subsection (i) above, (B) the bank will no longer be eligible to issue letters of credit in favor of the ISO, (C) any letters of credit issued by such bank in favor of the ISO will not be renewed, and (D) any letters of credit

issued by such bank in favor of the ISO must be replaced with another acceptable form of financial assurance within five (5) Business Days from the date on which the ISO provides notice of such failure (the ISO may extend that cure period to twenty (20) Business Days in its sole discretion). For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the expiration of the five (5) or twenty (20) Business Day cure period, as applicable. Notwithstanding the foregoing, the ISO in its sole discretion may reinstate eligibility after not less than two years from the loss of eligibility, provided that the bank otherwise meets the conditions of this Section X.B.2.

3. Form of Letter of Credit

Attachment 2 provides a generally acceptable sample "clean" letter of credit, and all letters of credit provided by Posting Entities shall be in this form (with only minor, non-material changes), unless a variation therefrom is approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and filed with the Commission. Notwithstanding the foregoing, Posting Entities that have provided a letter of credit in a form that was previously acceptable (e.g., under a prior version of Attachment 2) shall not be required to resubmit such letter of credit until the earlier of (a) the amendment or expiration of such letter of credit, in which case Posting Entity shall be required to provide a letter of credit in the form of Attachment 2, or (b) September 1, 2026. Any letter of credit provided for a new Posting Entity, for the purpose of covering the Initial Market Participant Financial Assurance Requirement, must have a minimum term of 120 days. All costs incurred by the ISO in collecting on a letter of credit provided under the ISO New England Financial Assurance Policy shall be paid, or reimbursed to the ISO, by the Posting Entity providing that letter of credit.

C. Special Provisions for Provisional Members

Notwithstanding any other provision of the ISO New England Financial Assurance Policy to the contrary, due to the temporary nature of a Market Participant's status as a Provisional Member and the relatively small amounts due from Provisional Members, any Provisional Member required to provide additional financial assurance under the ISO New England Financial Assurance Policy may only satisfy the portion of that requirement attributable to Participant Expenses under the RNA by providing collateral maintained in a shareholder account in accordance with Section X.A. Provisional

Members will not have any other Non-Hourly Requirements under the ISO New England Financial Assurance Policy. If a Provisional Member uses a standing instruction to pay its Invoices pursuant to the ISO New England Billing Policy, in order to avoid a default and/or a Late Payment Charge, the total amount of collateral maintained in a shareholder account by that Provisional Member should be equal to the sum of (x) the Provisional Member's Financial Assurance Requirement under the ISO New England Financial Assurance Policy that is attributable to Participant Expenses under the RNA and (y) the amount due from that Provisional Member on its next Invoice under that ISO New England Billing Policy (not including the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Provisional Member). Provisional Members are also required to satisfy all other provisions of the ISO New England Financial Assurance Policy, and any additional financial assurance required to be provided by a Provisional Member that is not attributable to Participant Expenses may be satisfied by providing an acceptable form of financial assurance in accordance with this Section X. Without limiting or reducing in any way the requirements of the ISO New England Financial Assurance Policy that apply to a Provisional Member, the amount of collateral maintained in a shareholder account initially provided by a Provisional Member that is attributable to Participant Expenses (including any amounts provided in connection with the standing instruction under the ISO New England Billing Policy described above) shall be at least $2,500, and each Provisional Member will replenish that collateral maintained in a shareholder account to at least that $2,500 level on December 31 of each year.

XI. MISCELLANEOUS PROVISIONS

A. Obligation to Report Material Adverse Changes

Each Market Participant and each Non-Market Participant Transmission Customer is responsible for informing the ISO in writing within five (5) Business Days of any Material Adverse Change in its financial status. A "Material Adverse Change" in financial status includes, but is not limited to, the following: a downgrade to below an Investment Grade Rating by any Rating Agency; being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating; a bankruptcy filing or other insolvency; a report of a significant quarterly loss or decline of

earnings; the resignation of key officer(s); the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principals imposed by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; or a significant change in the Market Participant's or Non-Market Participant Transmission Customer's market capitalization. A Market Participant's or Non-Market Participant Transmission Customer's failure to timely disclose a Material Adverse Change in its financial status may result in termination proceedings by the ISO. If the ISO determines that there is a Material Adverse Change in the financial condition of a Market Participant- or Non-Market Participant Transmission Customer, then the ISO shall provide to that Market Participant or Non-Market Participant Transmission Customer a signed written notice two Business Days before taking any of the actions described below. The notice shall explain the reasons for the ISO's determination of the Material Adverse Change. After providing notice, the ISO may take one or more of the following actions: (i) require that, within two Business Days of receipt of the notice of Material Adverse Change, the Market Participant or Non-Market Participant Transmission Customer provide one of the forms of financial assurance described in Section X of the ISO New England Financial Assurance Policy and/or an additional amount of financial assurance in one of the forms of financial assurance described in Section X of the ISO New England Financial Assurance Policy; (ii) require that the Market Participant or Non-Market Participant Transmission Customer cease one or more transactions in the New England Markets; or (iii) require that the Market Participant or Non-Market Participant Transmission Customer take other measures to restore the ISO's confidence in its ability to safely transact in the New England Markets. Any additional amount of financial assurance required as a result of a Material Adverse Change shall be sufficient, as reasonably determined by the ISO, to cover the Market Participant's or Non-Market Participant Transmission Customer's potential settled and unsettled liability or obligation, provided, however, that if the additional amount of financial assurance required as a result of a Material Adverse Change is equal to or greater than $25 million, then the Chief Financial Officer shall first consult, to the extent practicable, with the ISO's Chief Executive Officer, Chief Operating Officer, and General Counsel. If the Market Participant or Non-Market Participant Transmission Customer fails to comply

with any of the requirements imposed as a result of a Material Adverse Change, then the ISO may initiate termination proceedings against the Market Participant or Non-Market Participant Transmission Customer.

B. Weekly Payments

A Market Participant or Non-Market Participant Transmission Customer may request that, in lieu of providing the entire amount of one of the financial assurances set forth above to satisfy its Financial Assurance Requirement, a weekly billing schedule be implemented for its Non-Hourly Charges and its Transmission Charges. The ISO may, in its discretion, agree to such a request; provided, however, that any weekly billing arrangement for Non-Hourly Charges and Transmission Charges will terminate no more than six (6) months after the date on which such arrangement begins unless the Market Participant or Non-Market Participant Transmission Customer requests an extension of such arrangement and demonstrates to the ISO's satisfaction in its sole discretion that the termination of such arrangement and compliance with the other provisions of the ISO New England Financial Assurance Policy (including providing the full amount of its Financial Assurance Requirement) will impose a substantial hardship on the Market Participant or Non-Market Participant Transmission Customer. Such demonstration of a substantial hardship shall be made every six (6) months after the initial demonstration, and a Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement for Non-Hourly Charges and Transmission Charges will be terminated if it fails to demonstrate to the ISO's satisfaction in its sole discretion at any such six (6) month interval that compliance with the other provisions of the ISO New England Financial Assurance Policy will impose a substantial hardship on it. If the ISO agrees to implement a weekly billing schedule for Non-Hourly Charges and Transmission Charges for a Market Participant or Non-Market Participant Transmission Customer, the Market Participant or Non-Market Participant Transmission Customer shall be billed weekly for such Non-Hourly Charges and Transmission Charges in accordance with the ISO New England Billing Policy. The Market Participant or Non-Market Participant Transmission Customer shall pay with respect to each weekly Invoice for Non-Hourly Charges and Transmission Charges an administrative fee, determined by the ISO, to reimburse the ISO for the costs it incurs as a result of that Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement.

If a weekly billing schedule is implemented for a Market Participant's or Non-Market Participant Transmission Customer's Non-Hourly Charges and Transmission Charges under this Section XI.B, the Market Participant or Non-Market Participant Transmission Customer may be required to provide the full amount of its Financial Assurance Requirement at any time if the Market Participant or Non-Market Participant Transmission Customer fails to pay when due any weekly Invoice. In addition, upon the termination of a Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement for Non-Hourly Charges and Transmission Charges, the Market Participant or Non-Market Participant Transmission Customer shall either satisfy the applicable rating requirements set forth herein, satisfy the Credit Threshold, or provide the full amount of one of the other forms of financial assurance set forth herein.

C. Use of Transaction Setoffs

In the event that a Market Participant or Non-Market Participant Transmission Customer has failed to satisfy its Financial Assurance Requirement hereunder, the ISO may retain payments due to such Market Participant or Non-Market Participant Transmission Customer, up to the amount of such Market Participant's or Non-Market Participant Transmission Customer's unsatisfied Financial Assurance Requirement, as a cash deposit securing such Market Participant's or Non-Market Participant Transmission Customer's obligations to the ISO, NEPOOL, the Market Participants, the PTOs and the Non-Market Participant Transmission Customers, provided, however, that a Market Participant or Non-Market Participant Transmission Customer will not be deemed to have satisfied its Financial Assurance Requirement under the ISO New England Financial Assurance Policy because the ISO is retaining amounts due to it hereunder unless such Market Participant or Non-Market Participant Transmission Customer has satisfied all of the requirements of Section X with respect to such amounts.

D. Reimbursement of Costs

Each Market Participant or Non-Market Participant Transmission Customer that fails to perform any of its obligations under the Tariff, including without limitation those arising under the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, shall reimburse the ISO, NEPOOL and each Market Participant, PTO and

Non-Market Participant Transmission Customer for all of the fees, costs and expenses that they incur as a result of such failure.

E. Notification of Default

In the event that a Market Participant or Non-Market Participant Transmission Customer fails to comply with the ISO New England Financial Assurance Policy (a "Financial Assurance Default"), such failure continues for at least two days and notice of that failure has not previously been given, the ISO may (but shall not be required to) notify such Market Participant or Non-Market Participant Transmission Customer in writing, electronically and by first class mail sent in each case to such Market Participant's or Non-Market Participant Transmission Customer's billing and credit contacts or such Market Participant's member or alternate member on the Participants Committee (it being understood that the ISO will use reasonable efforts to contact all three where applicable), of such Financial Assurance Default. Either simultaneously with the giving of the notice described in the preceding sentence or within two days thereafter (unless the Financial Assurance Default is cured during such period), the ISO shall notify each other member and alternate on the Participants Committee and each Market Participant's and Non-Market Participant Transmission Customer's billing and credit contacts of the identity of the Market Participant or Non-Market Participant Transmission Customer receiving such notice, whether such notice relates to a Financial Assurance Default, and the actions the ISO plans to take and/or has taken in response to such Financial Assurance Default. In addition to the notices provided for herein, the ISO will provide any additional information required under the ISO New England Information Policy.

F. Remedies Not Exclusive

No remedy for a Financial Assurance Default is or shall be deemed to be exclusive of any other available remedy or remedies. Each such remedy shall be distinct, separate and cumulative, shall not be deemed inconsistent with or in exclusion of any other available remedy, and shall be in addition to and separate and distinct from every other remedy. A Financial Assurance Default may result in suspension of the Market Participant or Non-Market Participant Transmission Customer or the commencement of termination proceedings by the ISO.

G. Inquiries and Contests

A Market Participant or Non-Market Participant Transmission Customer may request a written explanation of the ISO's determination of its Market Credit Limit, Transmission Credit Limit, Financial Assurance Requirement or Transmission Obligations, including any change thereto, by submitting that request in writing to the ISO's Credit Department, either by email at CreditDepartment@iso-ne.com or by facsimile at (413) 540-4569. That request must include the Market Participant's customer identification number, the name of the Market Participant or Non-Market Participant Transmission Customer and the specific information for which the Market Participant or Non-Market Participant Transmission Customer would like an explanation and must be submitted by the designated credit contact for that Market Participant or Non-Market Participant Transmission Customer as on file with the ISO. In addition, since Financial Assurance Requirements are updated at least daily, any request for an explanation relating to the calculation of, or a change in, a Financial Assurance Requirement must be submitted on the same day as that calculation or change. The ISO's response to any request under this Section XI.G shall include an explanation of how the applicable calculation or determination was performed using the formulas and criteria in the ISO New England Financial Assurance Policy. A Market Participant or Non-Market Participant Transmission Customer may contest any calculation or determination by the ISO under the ISO New England Financial Assurance Policy using the dispute resolution provisions of Section I.6 of the Tariff.

H. Forward Contract/Swap Agreement

All FTR transactions constitute "forward contracts" and/or "swap agreements" within the meaning of the United States Bankruptcy Code (the "Bankruptcy Code"), and the ISO shall be deemed to be a "forward contract merchant" and/or "swap participant" within the meaning of the Bankruptcy Code for purposes of those FTR transactions. Pursuant to the ISO New England Financial Assurance Policy, the ISO Tariff and the Market Participant Service Agreement with each Market Participant, the ISO already has, and shall continue to have, the following rights (among other rights) in respect of a Market Participant default under those documents (including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy): A) the right to terminate and/or liquidate any FTR transaction held by that Market Participant; B) the right to immediately proceed against any additional financial assurance provided by that Market Participant; C) the right to set off any obligations due and owing to that Market

Participant pursuant to any forward contract, swap agreement or similar agreement against any amounts due and owing by that Market Participant pursuant to any forward contract, swap agreement or similar agreement, such arrangement to constitute a "master netting agreement" within the meaning of the Bankruptcy Code; and D) the right to suspend that Market Participant from entering into future transactions in the FTR system. For the avoidance of doubt, upon the commencement of a voluntary or involuntary proceeding for a Market Participant under the Bankruptcy Code, and without limiting any other rights of the ISO or obligations of any Market Participant under the Tariff (including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy) or any Market Participant Service Agreement, the ISO may exercise any of its rights against such Market Participant, including, without limitation 1) the right to terminate and/or liquidate any FTR transaction held by that Market Participant, 2) the right to immediately proceed against any additional financial assurance provided by that Market Participant, 3) the right to set off any obligations due and owing to that Market Participant pursuant to any forward contract, swap agreement and/or master netting agreement against any amounts due and owing by that Market Participant with respect to an FTR transaction including as a result of the actions taken by the ISO pursuant to 1) above, and 4) the right to suspend that Market Participant from entering into future transactions in the FTR system.

ATTACHMENT 1

SECURITY AGREEMENT

THIS SECURITY AGREEMENT (the "Security Agreement") is effective as of this [__] day of [_____], 20[_], by and between [INSERT NAME], a [_____], having its principal office and place of business at [_____] (the "Debtor"), and ISO New England Inc., a Delaware nonprofit corporation (the "Secured Party" and collectively with the Debtor, the "Parties").

WITNESSETH:

In consideration of the mutual promises and covenants herein contained, the Parties agree as follows:

1. Definitions.

a. In this Security Agreement:

i. "Code" shall mean the Uniform Commercial Code, as enacted in the State of Connecticut and as amended from time to time.

ii. "Collateral" shall mean (a) all cash provided, submitted, wired or otherwise transferred or deposited by the Debtor to or with the Secured Party or a financial institution, investment firm, or other designee selected by the Secured Party or acting on the Secured Party's behalf, to hold or invest such cash deposit, from time to time in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (b) all securities or other investment property (as defined in the Code) of the Debtor, whether or not purchased with such cash deposit, submitted, wired or otherwise transferred, deposited or maintained by the Debtor to or with the Secured Party or its designee, in each case in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (c) all other property of Debtor submitted, pledged, assigned or otherwise transferred by the Debtor to the Secured Party or its designee, in each case, in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; and (d) the products and proceeds of each of the foregoing.

iii. "ISO Financial Assurance Policy" shall mean the Financial Assurance Policy in the Tariff, as amended, supplemented or restated from time to time, including but not limited to the Financial Assurance Policy in Exhibit 1A to Section I of the Tariff.

iv. "Tariff" shall mean the ISO New England Inc. Transmission, Markets and Services Tariff, as filed with the Federal Energy Regulatory Commission, as amended, supplemented and/or restated from time to time.

v. "Obligations" shall mean any and all amounts due from Debtor from time to time under the Tariff.

vi. "Market Participants" shall have the meaning set forth in the Tariff.

b. Any capitalized term not defined herein that is defined in the Code shall have the meaning as defined in the Code.

2. Security Interest. To secure the payment of all Obligations of the Debtor, Debtor hereby grants and conveys to the Secured Party a security interest in the Collateral. The Debtor hereby irrevocably authorizes the Secured Party at any time and from time to time to file in any applicable filing office any initial financing statements and amendments thereto that provide any information required by part 5 of Article 9 of the Code for the sufficiency or filing office acceptance of any financing statement or amendment.

3. Debtor's Covenants. The Debtor warrants, covenants and agrees with the Secured Party as follows:

a. The Debtor shall perform all of the Debtor's obligations under this Security Agreement according to its terms.

b. The Debtor shall defend the title to the Collateral against any and all persons and against all claims.

c. The Debtor shall at any time and from time to time take such steps as the Secured Party may reasonably request to ensure the continued perfection and priority of the Secured Party's security interest in the Collateral and the preservation of its rights therein.

d. The Debtor acknowledges and agrees that this Security Agreement grants, and is intended to grant, a security interest in the Collateral. If the Debtor is a corporation, limited liability company, limited partnership or other Registered Organization (as that term is defined in Article 9 of the Uniform Commercial Code as in effect in Connecticut) the Debtor shall, at its expense, furnish to Secured Party a certified copy of Debtor's organization documents verifying its correct legal name or, at Secured Party's election, shall permit the Secured Party to obtain such certified copy at Debtor's expense. From

time to time at Secured Party's election, the Secured Party may obtain a certified copy of Debtor's organization documents and a search of such Uniform Commercial Code filing offices, as it shall deem appropriate, at Debtor's expense, to verify Debtor's compliance with the terms of this Security Agreement.

e. The Debtor authorizes the Secured Party, if the Debtor fails to do so, to do all things required of the Debtor herein and charge all expenses incurred by the Secured Party to the Debtor together with interest thereon, which expenses and interest will be added to the Obligations.

4. Debtor's Representations and Warranties. The Debtor represents and warrants to the Secured Party as follows:

a. The exact legal name of the Debtor is as first stated above.

b. Except for the security interest of the Secured Party, Debtor is the owner of the Collateral free and clear of any encumbrance of any nature.

5. Non-Waiver. Waiver of or acquiescence in any default by the Debtor or failure of the Secured Party to insist upon strict performance by the Debtor of any warranties, covenants, or agreements in this Security Agreement shall not constitute a waiver of any subsequent or other default or failure. No failure to exercise or delay in exercising any right, power or remedy of the Secured Party under this Security Agreement shall operate as a waiver thereof, nor shall any partial exercise of any right, power or remedy preclude any other or further exercise thereof or the exercise of any other right, power or remedy. The failure of the Secured Party to insist upon the strict observance or performance of any provision of this Security Agreement shall not be construed as a waiver or relinquishment of such provision. The rights and remedies provided herein are cumulative and not exclusive of any other rights or remedies provided at law or in equity.

6. Events of Default. Any one of the following shall constitute an "Event of Default" hereunder by the Debtor:

a. Failure by the Debtor to comply with or perform any provision of this Security Agreement or to pay any Obligation; or

b. Any representation or warranty made or given by the Debtor in connection with this Security Agreement proves to be false or misleading in any material respect; or

c. Any part of the Collateral is attached, seized, subjected to a writ or distress warrant, or is levied upon, or comes within the possession of any receiver, trustee, custodian or assignee for the benefit of creditors.

7. Remedy upon the Occurrence of an Event of Default. Upon the occurrence of any Event of Default the Secured Party shall, immediately and without notice, be entitled to use, sell, or otherwise liquidate the Collateral to pay all Obligations owed by the Debtor.

8. Attorneys' Fees, etc. Upon the occurrence of any Event of Default, the Secured Party's reasonable attorneys' fees and the legal and other expenses for pursuing, receiving, taking, keeping, selling, and liquidating the Collateral and enforcing the Security Agreement shall be chargeable to the Debtor.

9. Other Rights.

a. In addition to all rights and remedies herein and otherwise available at law or in equity, upon the occurrence of an Event of Default, the Secured Party shall have such other rights and remedies as are set forth in the Tariff and ISO Financial Assurance Policy.

b. Notwithstanding the provisions of the ISO New England Information Policy, as amended, supplemented or restated from time to time (the "ISO New England Information Policy"), Debtor hereby (i) authorizes the Secured Party to disclose any information concerning Debtor to any court, agency or entity which is necessary or desirable, in the sole discretion of the Secured Party, to establish, maintain, perfect or secure the Secured Party's rights and interest in the Collateral (the "Debtor Information"); and (ii) waives any rights it may have under the ISO New England Information Policy to prevent, impair or limit the Secured Party from disclosing such information concerning the Debtor.

10. PRE-JUDGMENT REMEDY. DEBTOR ACKNOWLEDGES THAT THIS SECURITY AGREEMENT AND THE UNDERLYING TRANSACTIONS GIVING RISE HERETO CONSTITUTE COMMERCIAL BUSINESS TRANSACTED WITHIN THE STATE OF CONNECTICUT. IN THE EVENT OF ANY LEGAL ACTION BETWEEN DEBTOR AND

THE SECURED PARTY HEREUNDER, DEBTOR HEREBY EXPRESSLY WAIVES ANY RIGHTS WITH REGARD TO NOTICE, PRIOR HEARING AND ANY OTHER RIGHTS IT MAY HAVE UNDER THE CONNECTICUT GENERAL STATUTES, CHAPTER 903a, AS NOW CONSTITUTED OR HEREAFTER AMENDED, OR OTHER STATUTE OR STATUTES, STATE OR FEDERAL, AFFECTING PREJUDGMENT REMEDIES, AND THE SECURED PARTY MAY INVOKE ANY PREJUDGMENT REMEDY AVAILABLE TO IT, INCLUDING, BUT NOT LIMITED TO, GARNISHMENT, ATTACHMENT, FOREIGN ATTACHMENT AND REPLEVIN, WITH RESPECT TO ANY TANGIBLE OR INTANGIBLE PROPERTY (WHETHER REAL OR PERSONAL) OF DEBTOR TO ENFORCE THE PROVISIONS OF THIS SECURITY AGREEMENT, WITHOUT GIVING DEBTOR ANY NOTICE OR OPPORTUNITY FOR A HEARING.

11. WAIVER OF JURY TRIAL. THE DEBTOR AND THE SECURED PARTY HEREBY EACH KNOWINGLY, VOLUNTARILY AND IRREVOCABLY WAIVES THE RIGHT TO TRIAL BY JURY IN ANY ACTION, DEFENSE, COUNTERCLAIM, CROSSCLAIM AND/OR ANY FORM OF PROCEEDING BROUGHT IN CONNECTION WITH THIS SECURITY AGREEMENT OR RELATING TO ANY OBLIGATIONS SECURED HEREBY.

12. Additional Waivers. Demand, presentment, protest and notice of nonpayment are hereby waived by Debtor. Debtor also waives the benefit of all valuation, appraisement and exemption laws.

13. Binding Effect. The terms, warranties and agreements herein contained shall bind and inure to the benefit of the respective Parties hereto, and their respective legal representatives, successors and assigns.

14. Assignment. The Secured Party may, upon notice to the Debtor, assign without limitation its security interest in the Collateral.

15. Amendment. This Security Agreement may not be altered or amended except by an agreement in writing signed by the Parties.

16. Term.

a. This Security Agreement shall continue in full force and effect until all Obligations owed by the Debtor have been paid in full.

b. No termination of this Security Agreement shall in any way affect or impair the rights and liabilities of the Parties hereto relating to any transaction or events prior to such termination date, or to the Collateral in which the Secured Party has a security interest, and all agreements, warranties and representations of the Debtor shall survive such termination.

17. Choice of Law. The laws of the State of Connecticut shall govern the rights and duties of the Parties herein contained without giving effect to any conflict-of-law principles.

IN WITNESS WHEREOF, the Parties have signed and sealed this Security Agreement as of the day and year first above written.

[INSERT NAME]

By: _____

Name:

Title:

ISO NEW ENGLAND INC.

By:_____

Name:

Title:

ATTACHMENT 2

SAMPLE STANDBY LETTER OF CREDIT

[DATE PROVIDED]

IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT NO.

[EXPIRATION DATE]

WE DO HEREBY ISSUE THIS IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT BY ORDER OF AND FOR THE ACCOUNT OF [POSTING ENTITY OR AFFILIATE OF POSTING ENTITY ON BEHALF OF POSTING ENTITY] ("ACCOUNT PARTY") IN FAVOR OF ISO NEW ENGLAND INC. ("ISO" OR "BENEFICIARY") ("STANDBY LETTER OF CREDIT").

THIS STANDBY LETTER OF CREDIT IS IRREVOCABLE AND IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS AND BONA FIDE HOLDERS OF THIS STANDBY LETTER OF CREDIT THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT WILL BE HONORED ON PRESENTATION OF THIS STANDBY LETTER OF CREDIT.

THIS STANDBY LETTER OF CREDIT IS AVAILABLE IN ONE OR MORE DRAFTS AND MAY BE DRAWN HEREUNDER FOR THE ACCOUNT OF THE ACCOUNT PARTY UP TO AN AMOUNT NOT EXCEEDING US$ _____.00 (UNITED STATES DOLLARS _____ AND 00/100) .

THIS STANDBY LETTER OF CREDIT IS DRAWN AGAINST BY PRESENTATION TO US AT OUR OFFICE LOCATED AT THE FOLLOWING ADDRESS:

_____

_____

_____;

OF A DRAFT IN THE FORM OF A DRAWING CERTIFICATE THAT IS SIGNED BY A PURPORTED OFFICER OR AUTHORIZED AGENT OF THE ISO AND DATED THE DATE OF

PRESENTATION CONTAINING THE FOLLOWING STATEMENT IN (1) BELOW ALONG WITH THE APPROPRIATE STATEMENT IN (2) BELOW:

(1) "THE UNDERSIGNED HEREBY CERTIFIES TO [BANK] ("ISSUER"), WITH REFERENCE TO IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT NO. [------] (THE "STANDBY LETTER OF CREDIT") ISSUED BY ISSUER IN FAVOR OF ISO NEW ENGLAND INC. ("ISO"), THAT

(2) [POSTING ENTITY] HAS FAILED TO PAY THE ISO, IN ACCORDANCE WITH THE TERMS AND PROVISIONS OF THE TARIFF FILED BY THE ISO, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____.];**OR**

[ISSUER HAS FAILED TO MAINTAIN A MINIMUM LONG-TERM DEBT RATING FROM ANY APPLICABLE RATING AGENCY (OR, IF THE ISSUER DOES NOT HAVE A MINIMUM LONG-TERM DEBT RATING, THEN A MINIMUM CORPORATE RATING) OF "A-" BY STANDARD AND POOR'S , OR "A3" BY MOODY'S OR "A-" BY FITCH, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____. **]; OR**

[**INCLUDE ONLY IN FORM IF LETTER OF CREDIT HAS A FIXED EXPIRATION DATE:]** [AS OF THE CLOSE OF BUSINESS ON _____, 20__ (FILL IN DATE WHICH IS WITHIN 30 DAYS BEFORE THE EXPIRATION DATE OF THE STANDBY LETTER OF CREDIT), [ACCOUNT PARTY] HAS FAILED TO RENEW THE STANDBY LETTER OF CREDIT IN A MANNER ACCEPTABLE TO THE ISO, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____. **]; OR**

[**INCLUDE ONLY IN FORM IF LETTER OF CREDIT HAS AUTOMATIC RENEWAL LANGUAGE:]** [AS OF THE CLOSE OF BUSINESS ON _____, 20__ (FILL IN DATE WHICH IS WITHIN 30 DAYS BEFORE THE EXPIRATION DATE OF THE STANDBY LETTER OF CREDIT IF NOT AUTORENEWING), WE HAVE BEEN PROVIDED NOTICE FROM [ACCOUNT PARTY] [ISSUER] THAT THE STANDBY LETTER OF CREDIT WILL NOT BE

EXTENDED FOR AN ADDITIONAL ONE (1) YEAR PERIOD, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____.]

IF PRESENTATION OF ANY DRAWING CERTIFICATE IS MADE ON A BUSINESS DAY AND SUCH PRESENTATION IS MADE AT OUR COUNTERS ON OR BEFORE 10:00 A.M. _____ TIME, WE SHALL SATISFY SUCH DRAWING REQUEST ON THE SAME BUSINESS DAY. IF THE DRAWING CERTIFICATE IS RECEIVED AT OUR COUNTERS AFTER 10:00 A.M. _____ TIME, WE WILL SATISFY SUCH DRAWING REQUEST ON THE NEXT BUSINESS DAY. FOR THE PURPOSES OF THIS SECTION, A BUSINESS DAY MEANS A DAY, OTHER THAN A SATURDAY OR SUNDAY, ON WHICH THE FEDERAL RESERVE BANK OF NEW YORK IS NOT AUTHORIZED OR REQUIRED TO BE CLOSED. DISBURSEMENTS SHALL BE IN ACCORDANCE WITH THE INSTRUCTIONS OF THE ISO.

THE FOLLOWING TERMS AND CONDITIONS APPLY:

THIS STANDBY LETTER OF CREDIT SHALL EXPIRE AT THE CLOSE OF BUSINESS [DATE] [AT LEAST 120 DAYS AFTER ISSUANCE FOR NEW POSTING ENTITIES].

[**INCLUDE ONLY IF LETTER OF CREDIT HAS A FIXED EXPIRATION DATE:]** [IF [ACCOUNT PARTY] HAS FAILED TO RENEW THIS STANDBY LETTER OF CREDIT IN A MANNER ACCEPTABLE TO THE ISO, YOU MAY DRAW ON THIS STANDBY LETTER OF CREDIT WITHIN THE THIRTY (30) DAYS PRIOR TO THE EXPIRY DATE BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.]

[**INCLUDE ONLY IF LETTER OF CREDIT IS TO HAVE AUTOMATIC RENEWAL LANGUAGE:]** [IT IS A CONDITION OF THIS STANDBY LETTER OF CREDIT THAT IT WILL BE AUTOMATICALLY EXTENDED WITHOUT AN AMENDMENT FOR A (1) YEAR PERIOD BEGINNING ON THE INITIAL EXPIRATION DATE HEREOF AND UPON EACH ANNIVERSARY OF SUCH DATE, UNLESS AT LEAST [THIRTY (30) **OR** SIXTY (60) **OR** NINETY (90)] DAYS PRIOR TO ANY SUCH EXPIRATION DATE WE HAVE SENT YOU, OR THE ACCOUNT PARTY HAS SENT YOU, WRITTEN NOTICE BY

REGULAR AND REGISTERED MAIL OR COURIER SERVICE THAT WE OR THE ACCOUNT PARTY ELECT NOT TO PERMIT THIS LETTER OF CREDIT TO BE SO EXTENDED, AND THAT THIS LETTER OF CREDIT WILL EXPIRE ON ITS THEN CURRENT EXPIRATION DATE. UPON RECEIPT OF SUCH NOTICE, YOU MAY DRAW ON THIS STANDBY LETTER OF CREDIT WITHIN THE THIRTY (30) DAYS PRIOR TO THE THEN RELEVANT EXPIRY DATE BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.]

IT IS A CONDITION OF THIS STANDBY LETTER OF CREDIT THAT WE SHALL MAINTAIN A MINIMUM LONG-TERM DEBT RATING (OR, IF WE DO NOT HAVE A MINIMUM LONG-TERM DEBT RATING, THEN A MINIMUM CORPORATE RATING) OF "A-" BY STANDARD AND POOR'S, OR "A3" BY MOODY'S OR "A-" BY FITCH. IN THE EVENT THAT WE ARE RATED BY MULTIPLE RATING AGENCIES, IF ANY APPLICABLE RATING FROM THE RATING AGENCIES FALLS BELOW THE LEVELS LISTED, THEN WE SHALL NOT BE CONSIDERED TO HAVE SATISFIED THIS CONDITION. IN THE EVENT THAT WE DO NOT SATISFY THE CONDITION REQUIRED BY THIS PARAGRAPH, YOU MAY DEMAND PAYMENT FROM US AT THE ADDRESS ABOVE, BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.

THE AMOUNT WHICH MAY BE DRAWN BY YOU UNDER THIS STANDBY LETTER OF CREDIT SHALL BE AUTOMATICALLY REDUCED BY THE AMOUNT OF ANY DRAWINGS HEREUNDER AT OUR COUNTERS. ANY NUMBER OF PARTIAL DRAWINGS ARE PERMITTED FROM TIME TO TIME HEREUNDER.

ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY.

THIS STANDBY LETTER OF CREDIT IS NOT TRANSFERABLE OR ASSIGNABLE. THIS STANDBY LETTER OF CREDIT DOES NOT INCORPORATE AND SHALL NOT BE DEEMED MODIFIED, AMENDED OR AMPLIFIED BY REFERENCE TO ANY DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE ISP, AS DEFINED BELOW) OR (B) IN WHICH THIS STANDBY

LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS STANDBY LETTER OF CREDIT RELATES.

THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE INTERNATIONAL STANDBY PRACTICES ("ISP98") OF THE INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NO. 590, INCLUDING ANY AMENDMENTS, MODIFICATIONS, OR REVISIONS THEREOF (THE "ISP"), EXCEPT TO THE EXTENT THAT THE TERMS HEREOF ARE INCONSISTENT WITH THE PROVISIONS OF THE ISP, IN WHICH CASE THE TERMS OF THIS STANDBY LETTER OF CREDIT SHALL GOVERN. THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY THE INTERNAL LAWS OF THE COMMONWEALTH OF MASSACHUSETTS TO THE EXTENT THAT THE TERMS ARE NOT GOVERNED BY THE ISP.

THIS STANDBY LETTER OF CREDIT MAY NOT BE AMENDED, CHANGED OR MODIFIED WITHOUT THE EXPRESS WRITTEN CONSENT OF THE ISO AND ISSUER.

WE HEREBY ENGAGE WITH YOU THAT DOCUMENTS DRAWN UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT SHALL BE DULY HONORED UPON PRESENTATION AS SPECIFIED AND WE REPRESENT THAT THE ACCOUNT PARTY IS NOT AN AFFILIATE OF THE ISSUER.

PRESENTATION OF ANY DRAWING CERTIFICATE UNDER THIS STANDBY LETTER OF CREDIT MAY BE SENT TO US BY COURIER, CERTIFIED MAIL, REGISTERED MAIL, OR FACSIMILE (WITH A CONFIRMING COPY OF SUCH FACSIMILE SENT AFTER THE DRAWING BY CERTIFIED MAIL TO THE ADDRESS SET FORTH BELOW; PROVIDED HOWEVER, THAT THE CONFIRMING COPY SHALL NOT BE A PREREQUISITE FOR US TO HONOR ANY PRESENTATION OTHERWISE MADE IN ACCORDANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT), OR SUCH OTHER ADDRESS AS MAY HEREAFTER BE FURNISHED BY US. OTHER NOTICES CONCERNING THIS STANDBY LETTER OF CREDIT MAY BE SENT BY SIMILAR COMMUNICATIONS FACILITY TO THE RESPECTIVE ADDRESSES SET FORTH BELOW. ALL SUCH NOTICES AND COMMUNICATIONS SHALL BE EFFECTIVE UPON RECEIPT BY THE INTENDED RECIPIENT PARTY.

IF TO THE BENEFICIARY OF THIS STANDBY LETTER OF CREDIT:

ISO NEW ENGLAND INC.
ATTENTION: CREDIT DEPARTMENT
1 SULLIVAN RD. HOLYOKE, MA 01040
FAX: 413-540-4569
EMAIL: CREDITDEPARTMENT@ISO-NE.COM

IF TO THE ACCOUNT PARTY:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

IF TO ISSUER:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

_____ _____

[SIGNATURE] [SIGNATURE]

ATTACHMENT 3

ISO NEW ENGLAND MINIMUM CRITERIA FOR MARKET PARTICIPATION OFFICER CERTIFICATION FORM

Certifying Entity:	

I,_____, a duly authorized Senior Officer of _____("Certifying Entity"), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the minimum criteria for market participation requirements set forth in Sections II.A.2 and II.A.3 of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Transmission, Markets and Services Tariff) (the "Policy"), hereby certify that I have full authority to bind Certifying Entity and further certify as follows:

1. Certifying Entity has established or contracted for written policies, procedures, and controls applicable to participation in the New England Markets, approved by Certifying Entity's independent risk management function[1], which provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Certifying Entity is exposed, including, but not limited to, credit risk, liquidity risk, concentration risk, default risk, operation risk, and market risk.

2. Certifying Entity has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets.

3. Certifying Entity has appropriate operating procedures and technical abilities to promptly and effectively respond to all ISO New England communications and directions.

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England's minimum criteria for market participation requirements and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

_____
(Signature)

Print Name:_____

Title: _____

Date: _____

[1] As used in this certification, a Certifying Entity's "independent risk management function" can include appropriate corporate persons or bodies that are independent of the Certifying Entity's trading functions, such as a risk management committee, a risk officer, a Certifying Entity's board or board committee, or a board or committee of the Certifying Entity's parent company.

ATTACHMENT 4

ISO NEW ENGLAND ADDITIONAL ELIGIBILITY REQUIREMENTS

CERTIFICATION FORM

Certifying Entity:	

I,_____, a duly authorized Senior Officer of _____("Certifying Entity"), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the additional eligibility requirements set forth in Section II.A.5 of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Inc. Transmission, Markets and Services Tariff) (the "Policy"), hereby certify that I have full authority to bind Certifying Entity and further certify as follows:

1. Certifying Entity is now and in good faith will seek to remain (check applicable box(es)):

   □ an "appropriate person," as defined in section(s) [ ] of the Commodity Exchange Act (7 U.S.C. § 1 *et seq*.) (specify which section(s) of Commodity Exchange Act sections 4(c)(3)(A) through (J) apply)) (if Certifying Entity is relying on section 4(c)(3)(F), it shall accompany this certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the Certifying Entity's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy);

   □ an "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or

   ☐ a "person who actively participates in the generation, transmission, or distribution of electric energy," as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

2. If at any time Certifying Entity no longer satisfies the criteria in paragraph 1 above, Certifying Entity will immediately notify ISO New England in writing and will immediately cease all participation in the New England Markets.

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England's additional eligibility requirements and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

_____

(Signature)

Print Name:_____

Title: _____

Date: _____

ATTACHMENT 5

ISO NEW ENGLAND CERTIFICATE REGARDING CHANGES TO SUBMITTED RISK MANAGEMENT POLICIES FOR FTR PARTICIPATION

Certifying Entity:	

I,_____, a duly authorized Senior Officer of _____("Certifying Entity"), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the annual certification requirement for FTR market participation regarding its risk management policies, procedures, and controls set forth in Section II.A.2(b) of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Inc. Transmission, Markets and Services Tariff) (the "Policy"), hereby certify that I have full authority to bind Certifying Entity and further certify as follows (check applicable box):

1. □ There have been no changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity's participation in the FTR market.

   OR

2. □ There have been changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity's participation in the FTR market and such changes are clearly identified and attached hereto.*

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England's risk management policy requirements for FTR market participants and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

_____

____

(Signature)

Print Name:_____

Title:

_____

Date:

_____

_____

* As used in this certificate, "clearly identified" changes may include a redline comparing the current written risk management policies, procedures, and controls and the previously submitted written risk management policies, procedures, and controls; or resubmission of the written risk management policies, procedures, and controls with a bulleted list of all changes, including section and/or page numbers.

ATTACHMENT 6

MINIMUM CRITERIA FOR MARKET PARTICIPATION

INFORMATION DISCLOSURE FORM

Date: _____

Prepared by: _____

Customer/Applicant:[1] _____

I, _____, a duly authorized Senior Officer of _____ ("Certifying Entity"), understanding that ISO New England Inc. ("ISO") is relying on this certification provided pursuant to Financial Assurance Policy Section II.A.1(a), hereby certify that I have full authority to bind Certifying Entity and further certify on behalf of Certifying Entity that the information contained herein is true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission:

1. List of all Principals.[2] Please discuss each Principal's relationship with the Certifying Entity and describe each Principal's previous experience related to participation in North American wholesale or retail energy markets or trading exchanges:

[1] Customer and Applicant are each defined in Section II.A of the ISO New England Financial Assurance Policy, Exhibit 1A to Section 1 of the ISO Transmission, Markets, and Services Tariff ("Tariff"). Capitalized terms used but not otherwise defined herein shall have the meaning given to them in the Tariff.

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

2. List all material litigation (criminal or civil) against Certifying Entity or any of the Certifying Entity's Principals, Personnel,[1] or Predecessors,[2] arising out of participation in any wholesale or retail energy market (domestic or international) or trading exchanges in the past ten (10) years:
(Enter N/A if not applicable)
3. List all sanctions issued against or imposed upon Certifying Entity, Certifying Entity's Principals, Personnel, or Predecessors, by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges where such sanctions were either imposed in the past ten (10) years or, if imposed prior to that, are still in effect. List all known material ongoing investigations regarding Certifying Entity, Certifying Entity's Principals, Personnel, or Predecessors, imposed by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges:
(Enter N/A if not applicable)

4. Provide a summary of any bankruptcy, dissolution, merger, or acquisition of Certifying Entity in the past ten (10) years (include date, jurisdiction, and other relevant details):
(Enter N/A if not applicable)

5. List all wholesale or retail energy market-related operations in North America where Certifying Entity is currently participating, or, in the past five (5) years, has previously participated other than in the New England Markets (e.g., PJM - FTRs):
(Enter N/A if not applicable)

6. Describe if Certifying Entity or any of Certifying Entity's Principals, Personnel, or any Predecessor of the foregoing ever had its participation or membership in any independent system operator or regional transmission organization (domestic or international) terminated, its registration/membership application denied, or is subject to an existing uncured suspension from participating in the markets of any independent system operator or regional transmission organization (domestic or international), each in the past five (5) years.
(Enter N/A if not applicable)

If you are currently an active participant and this is your annual submission you do not have to complete Question 7 and can skip to the signature block below. If you are in the process of applying for membership with the ISO you are required to answer the additional questions listed below.

7. Describe how Certifying Entity plans to fund its operations, including persons or entities providing financing and such person(s)' or entity(ies)' relationship to the Certifying Entity. Include any relationships that may impact Certifying Entity's ability to (a) comply with the time frames to post

[1] Personnel means any person, current or former, responsible for decision making regarding Certifying Entity's transaction of business in the New England Markets, including, without limitation, decisions regarding risk management and trading, or any person, current or former, with access to enter transactions into ISO systems. Disclosures regarding former Personnel shall only be required for when such Personnel was employed by Certifying Entity.

[4] Predecessor shall mean any person or entity whose liabilities, including liabilities arising under the Tariff, have or may have been retained or assumed by Certifying Entity, either contractually, by operation of law or considering all relevant factors, including the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base.

financial assurance and/or pay invoices or other amounts owed to the ISO, each as required by the Tariff; or (b) provide a first priority perfected security interest in required financial assurance to the ISO:

Certifying Entity: _____

By: _____
(Signature)

Print Name: _____

Title: _____

Date: _____

** To satisfy the disclosure requirements above, a Certifying Entity may attach additional materials and may provide the ISO with filings made to the SEC or other similar regulatory agencies that include substantially similar information to that required above, provided that Certifying Entity clearly indicates where the specific information is located in those filings.

EXHIBIT ID

ISO NEW ENGLAND BILLING POLICY

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SECTION 7 – WEEKLY BILLING PRINCIPLES FOR NON-HOURLY CHARGES

EXHIBIT ID ISO NEW ENGLAND BILLING POLICY

SECTION 1 – OVERVIEW

Section 1.1 – Scope. The objective of this ISO New England Billing Policy is to define the billing and payment procedures to be utilized in administering charges and payments due under the Transmission, Markets and Services Tariff and the ISO Participants Agreement, in each case as amended, modified, supplemented and restated from time to time (collectively, the "Governing Documents"). Capitalized terms used but not defined in the ISO New England Billing Policy shall have the meanings specified in Section I. The ISO New England Billing Policy applies to the ISO, the Market Participants, Non-Market Participant Transmission Customers, PTOs, and Market Participants that transact only in the FTR Auction ("FTR-Only Customers") (referred to herein collectively as the "Covered Entities" and individually as a "Covered Entity") for billing and payments procedures for amounts due under the Governing Documents, including without limitation those procedures related to the New England Markets. As reflected and specified in Section 3 hereof, the ISO's obligation to make Payments (as defined below) is contingent on its receipt of sufficient aggregate Charges (as defined below) (or in cases of defaults in Covered Entities' payments of Charges, on the ISO's drawdowns under the ISO New England Financial Assurance Policy or recovery using the mechanisms specified in Section 3, 4 and 5 hereof).

Section 1.2 – Financial Transaction Conventions. The following conventions have been adopted in defining sums of money to be paid or received under the ISO New England Billing Policy:

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

b) The term "Payment" refers to a sum of money due to a Covered Entity from the ISO. Amounts due to and from the ISO include amounts collected and paid by the ISO as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

c) Where a Covered Entity's total Charges exceed its total Payments for all amounts being billed together in a billing period, the ISO shall issue an "Invoice" for the net Charge owed by such Covered Entity.

d) Where a Covered Entity's total Payments exceed its total Charges for all amounts being billed together in a billing period, the ISO shall issue a "Remittance Advice" for the net Payment owed to the Covered Entity. Invoices and Remittance Advices are collectively referred to herein as "Statements."

Section 1.3 – General Process. Except for special billings, as described in Section 1.4 below, the billing process is performed (i) twice weekly for each complete-day settlement amount for the hourly charges and payments for Real-Time Energy and Day-Ahead Energy and for each complete-day settlement amount for the hourly charges and payments for Real-Time Operating Reserve, Forward Reserves, Regulation service, Emergency Sales, Emergency Purchases, Net Commitment Period Compensation, daily Forward Capacity Market charges and payments ("Daily FCM Charges"), and Inventoried Energy Program charges and payments under Section III, Appendix K of the ISO Transmission, Markets and Services Tariff (all such charges and payments described in this clause (i) being referred to collectively as the "Hourly Charges"); (ii) monthly for all other charges and payments, including without limitation charges relating to the monthly markets, the monthly Forward Capacity Market (exclusive of settlements included in the Hourly Charges) and other ancillary services, Participant Expenses, charges under Section IV of the ISO Transmission, Markets and Services Tariff, monthly meter adjustments, Qualification Process Cost Reimbursement Deposits (including the annual true-up of those Qualification Process Cost Reimbursement Deposits), state sales tax and related charges, any pass-through charges where the ISO acts as agent (including communications related charges, Open Access Same-Time Information System related charges, and fees related to the Shortfall Funding Arrangement), and charges under the OATT (*other than* charges arising under Schedules 1, 8, and 9 to the OATT, which charges are addressed in clause (iii) below) (all such charges and payments described in this clause (ii) being referred to collectively as ("Non-Hourly Charges" and, together with Hourly Charges, as "ISO Charges"), except in the case of Covered Entities who have requested and received a weekly payment arrangement for Non-Hourly Charges under the ISO New England Financial Assurance Policy that is Exhibit IA to Section I of the ISO Transmission, Markets and Services Tariff (the "ISO New England Financial Assurance Policy"); and (iii) monthly for all charges and payments under Schedules 1, 8 and 9 to the OATT (all such

charges and payments described in this clause (iii) being referred to collectively as "Transmission Charges"). There are two major steps in the billing process:

a) *Statement Issuance*. The ISO will issue an Invoice or Remittance Advice showing the net amounts due from or owed to a Covered Entity. This Statement is determined from the preliminary statements of the New England Markets, applicable the ISO Charges and/or Transmission Charges due under the Governing Documents (including amounts due under the ISO New England Financial Assurance Policy), as well as applicable adjustments. Prior to January 1 of any calendar year, the ISO will post or make available a list of the dates in the new calendar year on which Statements will be issued, due and paid. Billing and payment holidays will be the same as the ISO's settlement holidays, as listed on the ISO's website from time to time.

b) *Electronic Funds Transfer ("EFT").* EFTs related to Invoices and Remittance Advices are performed in a two-step process, as described below, in which all Invoices are paid first and all Remittance Advices are paid later.

Section 1.4 – Special Billings. In addition to the regular billing process described above, the ISO will issue special, extraordinary Statements as and when required under the Governing Documents or in order to adjust for special circumstances. Such Statements shall be payable in accordance with the instructions set forth therein.

Section 1.5 – Conflicts with Governing Documents. Except as set forth herein, to the extent any provision hereof conflicts with any provision of any Governing Document, the provision in the Governing Document shall govern.

SECTION 2 - TIMING AND CONTENT OF STATEMENTS.

Section 2.1 – Statements for Hourly Charges. On each Monday and each Wednesday or on the following Business Day if such Monday or Wednesday is not a Business Day, the ISO shall provide electronically to each Covered Entity a Statement showing all complete-day settlement amounts for each of the Hourly Charges incurred and not reflected on a previously issued Statement. Each such Statement will cover only days with complete settled data. Accordingly,

some Statements may have fewer days of settled data for certain Hourly Charges if fewer days have been settled for those Hourly Charges on the morning of the day that such Statements are issued; a following Statement may have more days of settled data for those Hourly Charges when it becomes possible to catch up on the settled data. Statements will include contiguous month-to-month hourly market billing data and will have separate line items for any hourly market data that may cross calendar months. For example, if a Statement's billing period includes May 30 through June 2, and all of those days are fully settled, the June 8 Statement would have one line item for the period May 30 to May 31 and one line item for the period June 1 to June 2. The Job Aid on the ISO web site will be updated weekly for any information necessary to be distributed through that medium.

Section 2.2 – Monthly Statements for Non-Hourly Charges. The first Statement issued on a Monday after the ninth of a calendar month will include both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month (hereinafter sometimes referred to as a "Monthly Statement"). Resettlements determined in accordance with the procedures set forth in Market Rule 1 will be included in the monthly Statement for Non-Hourly Charges.

Section 2.3 – Statements for Weekly Billing Non-Hourly Charges. The ISO shall implement any weekly billing arrangements for Non-Hourly Charges effected under the ISO New England Financial Assurance Policy in accordance therewith and with the procedures set forth in Section 7 below.

Section 2.4 – Contents of Statements. Each Statement for Hourly and Non-Hourly Charges will include all of the following line items that are applicable to the Covered Entity receiving such Statement for the period to which such Statement relates:

a) *Invoice or Remittance Advice Amount*. The net amount of all Charges and Payments owed by or due to a Covered Entity for the relevant Statement. The ISO shall issue an Invoice where the Covered Entity owes monies. The ISO shall issue a Remittance Advice where the Covered Entity is owed monies.

b) *OATT Charges and Payments.* The Charges owed by and the Payments owed to the Covered Entity under the OATT *other than* Transmission Charges, which are billed separately under Section 2.5 below.

c) *ISO Self-Funding Charges.* The Charges owed by the Covered Entity under Section IV of the Transmission, Markets and Services Tariff, categorized by the section or schedule under which such Charges arise.

d) *Markets Charges and Payments.* The Hourly Charges owed by and the Payments for Hourly Charges owed to the Covered Entity as a result of transactions in each of the New England Markets administered by the ISO under Section III of the Transmission, Markets and Services Tariff.

e) *Monthly Forward Capacity Market Charges and Payments.* The Non-Hourly Charges owed by and the Payments for Non-Hourly Charges owed to the Covered Entity as a result of Capacity Performance Payments, System-Backed Export Charges, and other transactions in the Forward Capacity Market.

f) *Participant Expenses*. As defined in the Participants Agreement, the Covered Entity's share of costs and expenses that are incurred pursuant to authorization of the Participants Committee and are not considered costs and expenses of ISO.

g) [Reserved for Future Use]

h) *Other Amounts due under the Participants Agreement.* The Charges owed by or the Payments owed to the Covered Entity under the Participants Agreement to the extent that those amounts are not included in items (b)-(g) above.

i) *Other Non-Hourly Charges, Payments or Adjustments*. Any other Non-Hourly Charges, Payments for Non-Hourly Charges, or adjustments owed by or to the Covered Entity that are not included in items (b)-(h) above. These items may be due to retroactive billing adjustments, late payment fees, penalties or other items collectible under the Governing Documents.

j) *Billing Periods*. The billing period (from and to dates) covered for each line item on the Statement. The billing periods for the various line items are not necessarily the same because of differences in timing of settlements and because of retroactive adjustments.

k) *Payment Due Date and Time.* If the Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO.

l) *Wire Transfer Instructions*. Details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which ISO Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for ISO Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.5 – Monthly Statements for Transmission Charges. On the same date when each Monthly Statement is issued, the ISO shall provide electronically to each Covered Entity owing or owed any Transmission Charges for the preceding month a Statement (which may be combined with that Monthly Statement) showing all of the Transmission Charges for that Covered Entity for that preceding month (hereinafter sometimes referred to as a "Transmission Statement"). Any resettlements of Transmission Charges will also be included on the Transmission Statement. Each Transmission Statement will also include: (i) the billing month covered by the Transmission Statement; (ii) if the Transmission Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO; and (iii) details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which Transmission Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for Transmission Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.6 – Certain Subsequent Adjustments to Previously Issued Statements.

a) *Adjustments Requested by Covered Entities*. Covered Entities supplying Regional Network Load and other input data to the ISO for use by the ISO in developing Statements shall use reasonable care to assure that the data supplied is complete and accurate. Should a Covered Entity supplying input data subsequently determine that the data supplied was incorrect, that Covered Entity shall notify the ISO promptly of the error and submit corrected data as soon as practicable. All errors in input data for a calendar month shall be corrected in one submission. If the error is detected and corrected data is provided within the time frames set forth below, the ISO will issue corrected Statements to reflect the newly supplied data.

Type of Adjustment	**Corrected Data Must be Submitted By**
Adjustments to Monthly Regional Network Load Submissions	20th day of the fourth (4th) month after the Regional Network Load Month
Adjustments to Annual Revenue Requirements Submissions	Annually during the rate development process, which is administered by the PTO Working Group
Adjustments to Annual Transmission, Markets and Services Tariff Section II, Schedule I Submissions	Annually during the rate development process, which is administered by the PTO Working Group

If the data correction is not submitted within the applicable time frame set forth above, the obligation of the ISO to issue corrected Statements reflecting that adjustment shall be as set forth in a written re-billing protocol, developed in consultation with the NEPOOL Budget and Finance Subcommittee, and as may be amended from time to time in consultation with the NEPOOL Budget and Finance Subcommittee, and posted on the ISO website. The re-billing protocol shall provide, for each category of adjustment listed above, whether and to what extent the adjustment shall be prospective or retroactive and the timing of the adjustment. If the corrected data is not submitted within the applicable time frame, the ISO may assess each Covered Entity submitting corrected data on an untimely basis its costs in generating and issuing the corrected Statement. The written re-billing protocol shall include a fee schedule for this purpose.

b) *Adjustments Triggered by ISO Audit*. The ISO will review the results of internal and outsourced audits with the PTO Administrative Committee and the Participants Committee or its delegee. The reasonable costs to the ISO of the re-billing shall be allocated to Schedule 1 of Section IV of the Transmission, Markets and Services Tariff.

c) *Adjustments Reflecting Compliance with an Order of the Commission or other Regulatory or Judicial Authority With Jurisdiction*. Adjustments required to effect compliance with an order of the Commission (or any other regulatory or judicial authority with jurisdiction to interpret and/or enforce the provisions of the Governing Documents) shall be completed by the ISO in compliance with such order. The costs of any such re-billing to the ISO shall be allocated among the Covered Entities in accordance with the provisions of the Transmission, Markets and Services Tariff.

d) Nothing in this Section 2.6 shall affect resettlements of the New England Markets under Market Rule 1.

SECTION 3 – PAYMENT PROCEDURES.

All Payments (including prepayments as described in Section 3.1(e) below) made by the ISO will in all instances be made by EFT or in immediately available funds payable to the account designated to the ISO by the Covered Entity to which such Payment is due. Payments made by Covered Entities shall be made by EFT to the account designated by the ISO.

Section 3.1 – Invoice Payments.

a) *Payment Date*. Except in the case of special billings, all Charges due shall be paid to and received by the ISO not later than the second (2nd) Business Day after the Invoice on which they appeared was issued (the "Invoice Date") so long as the ISO issues such Invoice to the Covered Entities by 11:00 a.m. Eastern Time on the Invoice Date. If the ISO issues an Invoice after 11:00 a.m. Eastern Time on the Invoice Date, the charges on such Invoice will be paid not later than the third (3rd) Business Day after such Invoice Date. Notwithstanding the

foregoing, a Non-Market Participant Transmission Customer will in no event be required to make a payment on an Invoice any sooner than provided in Section II of the Transmission, Markets and Services Tariff.

b) *Right to Alter Payment Date*. The ISO may establish the dates on which payments are due in the case of a special billing; provided, however, that, (i) payment on any special billing invoice shall not be due prior to the second (2nd) Business Day after the Invoice is issued, and (ii) a Non-Market Participant Transmission Customer shall not be required to make a payment on an Invoice any sooner than provided in Section II of the Transmission, Markets and Services Tariff.

c) *Payments Received by the ISO*. Each Covered Entity owing monies to the ISO, either in the ISO's individual capacity, or as agent for NEPOOL, shall remit the amount shown on its Invoice no later than the date such payment is due. Disputed Amounts shall be paid in accordance with clause (d) below. All Invoices shall be paid by EFT, except that (i) Covered Entities (other than Unqualified New Market Participants and Returning Market Participants under the ISO New England Financial Assurance Policy that are not Provisional Members) may, and any Provisional Member must, pay any Invoice for ISO Charges (but not for Transmission Charges) by instructing the ISO (either on a case-by-case basis or pursuant to a standing instruction) in writing to draw on collateral maintained in a shareholder account created pursuant to the ISO New England Financial Assurance Policy provided by such Covered Entity under the ISO New England Financial Assurance Policy for such Invoice, provided that the failure of a Provisional Member to provide such an instruction to the ISO shall not, in and of itself, be deemed to be a default under the ISO New England Billing Policy and (ii) any Covered Entity may instruct the ISO to auto-debit an account identified by that Covered Entity to pay all Invoices issued by the ISO and in such case the Covered Entity will direct the bank or other institution holding that account to permit the ISO to auto-debit that account to pay all such Invoices on the date they are due. Any instruction to pay any Invoice by drawing on collateral maintained in a shareholder account or to auto-debit an account must be received by at least 5:00 p.m. (Eastern Time) on the day that is two

Business Days prior to the Invoice Date. The amount of a Covered Entity's collateral maintained in a shareholder account will immediately be reduced by the amount drawn to pay an Invoice for ISO Charges pursuant to a standing instruction. Nothing set forth in this section will reduce the financial assurance obligation otherwise applicable to any Covered Entity that instructs the ISO to draw on collateral maintained in a shareholder account or to auto-debit an account to pay an Invoice, and the ISO is not liable for any default resulting from a draw on collateral maintained in a shareholder account to pay an Invoice or for any overdraft charges resulting from any auto-debit.

d) *Payments Pending Resolution of a Dispute.* Any Covered Entity that disputes the amount due, including an amount due for Participant Expenses, on any Invoice for service other than transmission service under Section II of the Transmission, Markets and Services Tariff shall pay to the ISO all amounts due on such Invoice, including any such Disputed Amounts. Such payment shall in no way prejudice the right of such Covered Entity to seek reimbursement of such Disputed Amounts, including accrued interest on such amounts at the Commission's standard rate, set forth in 18 C.F.R. Section 35.19, pursuant to the Billing Dispute Resolution Procedures provided in Section 6 below.

Any Covered Entity that disputes the amount due on any Invoice for transmission service under the Transmission, Markets and Services Tariff shall pay to the ISO all amounts not in dispute in accordance with the ISO New England Billing Policy and shall pay (or, in the case of an auto-debit payment or a payment for ISO Charges pursuant to a standing instruction, as described above, direct the ISO to pay) such Disputed Amounts into an independent escrow account designated by the ISO, which account shall be established at a banking institution acceptable to the ISO and the Covered Entity challenging the amount due and shall accrue interest at a prevailing market rate. Such amount in dispute shall be held in escrow pending the resolution of such dispute in accordance with the applicable Governing Document(s). The shortfall of funds available to pay Remittance Advices resulting from the amount in dispute being held in an escrow account shall be allocated among the Covered Entities according to the two-step allocation process described in Section 3.3 (for ISO Charges) and in Section 3.4

(for Transmission Charges) for the applicable type of Covered Entity disputing the Charges, subject to payment to all Covered Entities being allocated a portion of the shortfall, with applicable interest (if any), once the dispute is resolved with the funds in such escrow account or with other amounts provided by the Covered Entity losing such dispute.

e) *Prepayments*. A Covered Entity may prepay any Invoice, in whole or in part, according to the following procedures:

(i) only two such prepayments shall be made by any Covered Entity in any calendar week; only five such prepayments shall be made in any rolling 365-day period; and no prepayments shall be made on a Friday;

(ii) each prepayment will be applied only to the next subsequent Invoice issued;

(iii) prepayments and payments for issued Invoices must be made in separate wire transfers;

(iv) for purposes of calculating a Covered Entity's financial assurance obligations under the ISO New England Financial Assurance Policy, prepayments will be applied first to Hourly Charges, then any remaining prepayment will offset the Covered Entity's financial assurance obligations on a dollar-for-dollar basis;

(v) if ISO Charges and Transmission Charges are billed on separate Invoices, then separate prepayments must be made for those ISO Charges and Transmission Charges (the ISO will account for each prepayment separately and will only apply each prepayment to the designated Charges);

(vi) if a prepayment exceeds the amount due on the next subsequent Invoice issued, then the prepayment will be applied to that Invoice first, and then to the extent any amount is left after paying that Invoice, the Covered Entity making that prepayment may direct at the time of the prepayment that the excess be deposited with its collateral maintained in a shareholder account created pursuant to the ISO New England Financial Assurance Policy, and if the Covered Entity does not direct the ISO to make that deposit, the excess will be returned to the Covered Entity. Under either circumstance, the deposit to the shareholder account or the return of excess funds will occur on the next date when the ISO pays Remittances; and

(vii) all prepayments will be held in the ISO's settlement account until the Invoice payments are due, and no interest will be paid to any Covered Entity on any prepayments provided by it.

Section 3.2 – ISO Payment of Remittance Advice Amounts. The Payment Date for a Remittance Advice shall be the fourth (4th) Business Day following the date on which the Remittance Advice was issued (the "Remittance Advice Date") so long as the ISO issues such Remittance Advice by 11:00 a.m. Eastern Time on the Remittance Advice Date. If the ISO issues a Remittance Advice after 11:00 a.m. Eastern Time on the Remittance Advice Date, the Payment Date for that Remittance Advice shall be the fifth (5th) Business Day after the Remittance Advice Date.

Section 3.3 -Payment Default for ISO Charges. If the ISO, in its reasonable opinion, believes that all or any part of any amount of ISO Charges due to be paid to the ISO by any Covered Entity will not or has not been paid when due (other than in the case of (i) a payment dispute for any amount due for transmission service under the OATT or (ii) any amounts due for NEPOOL GIS API Fees) (the "Default Amount"), then the following procedures shall apply:

a) *Priority of Payments*. The ISO shall use moneys received by it from Covered Entities for an Invoice for ISO Charges to pay all amounts due to the ISO under Section IV of the Transmission, Markets and Services Tariff, all amounts due to NEPOOL for Participant Expenses, and all amounts due to the ISO for acting as Project Manager for the generation information system (the "NEPOOL GIS") before making any payments to any Covered Entities. After paying all amounts due to the ISO and NEPOOL but prior to making any payments to any Covered Entities, the ISO shall use moneys received by it from Covered Entities for ISO Charges to pay all amounts due from NEPOOL to the entity or entities that develop, administer, operate and maintain the NEPOOL GIS (the "NEPOOL GIS Administrator") for those services (other than NEPOOL GIS API Fees). After paying all amounts due to the ISO and NEPOOL for Participant Expenses and all amounts due to the NEPOOL GIS Administrator for the development, administration, operation and maintenance of the NEPOOL GIS but prior to making any payments to any Covered Entities, the ISO shall use moneys received by it from Covered Entities for ISO Charges to pay any and all amounts due with respect to the Shortfall Funding Arrangement. NEPOOL GIS API Fees

shall only be paid to the NEPOOL GIS Administrator to the extent that each Covered Entity or NEPOOL Participant owing such NEPOOL GIS API Fees has paid the full amount of all ISO Charges due on the Statement on which such NEPOOL GIS API Fees appear.

b) *Use of Set-Offs.* The ISO shall use any and all rights of set-off it has under the Governing Documents, including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy against a defaulting Covered Entity with respect to ISO Charges due to that Covered Entity to the extent necessary to pay the Default Amount, together with any interest accrued thereon and any late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, due from such Covered Entity.

c) *Enforcing the Security of a Defaulting Party*. If and to the extent that the procedure described in clause (b) above is insufficient to effect payment of the Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall use the financial assurance(s) provided by the defaulting Covered Entity under the ISO New England Financial Assurance Policy to the extent necessary to pay the Default Amount and such interest and late charges. Any use of financial assurance(s) shall be undertaken in compliance with the ISO New England Financial Assurance Policy.

d) *Action Against a Defaulting Party or Recovery from an FCM Affiliate Guaranty.* If and to the extent that the procedures described in clauses (b) and (c) above are insufficient to effect payment of the Default Amount and the Covered Entity has an FCM Affiliate Guaranty (as described in Section VII of the ISO New England Financial Assurance Policy) in place, the ISO shall use the monies received from the guarantor under such guaranty to cover the portion of the Default Amount related to a Capacity Performance Payment. If and to the extent that the procedures described in clauses (b) and (c) above are insufficient to effect payment of the Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall take appropriate actions to recover the

Default Amount and such accrued interest and late charges, which actions may include, without limitation, initiating proceedings in accordance with the appropriate dispute resolution mechanisms or actions with Covered Entities or before the Commission or a court of competent jurisdiction against the defaulting Covered Entity. Before initiating any such proceedings, the ISO shall consult with the Chair of the NEPOOL Budget and Finance Subcommittee or NEPOOL counsel. Any amounts incurred by the ISO or any Market Participant in connection with any such action or proceeding shall be paid by the defaulting Covered Entity.

e) *Late Payment Account.* If and to the extent that the procedures described in clauses (b), (c) and (d) above are insufficient to effect payment of the Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) by the time the corresponding Payment to the Covered Entities is due, the ISO shall withdraw from the Late Payment Account, as that term is defined in Section 4 of the ISO New England Billing Policy, an amount equal to such unpaid Default Amount, to the extent that such amount is available in the Late Payment Account, and shall apply such amount to any shortfall in Payments resulting from the Default Amount not being paid. To the extent that the amount on deposit in the Late Payment Account on any date is insufficient to pay all Unsecured Default Amounts and Uncovered Default Amounts (each as defined below) on that date, the amount in the Late Payment Account shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts on or total Unsecured Default Amounts outstanding. Amounts withdrawn from the Late Payment Account and applied toward any shortfall resulting from the Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Default Amount. If and to the extent that such Default Amount, interest thereon and/or late charges with respect thereto are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the defaulting Covered Entity), such

amounts shall first be used to pay Covered Entities for the amount of such Default Amount allocated to them under clauses (h), (i) and (j) below, with interest thereon, and then, after all such amounts have been paid to Covered Entities, such Default Amount, interest and/or late charges shall be deposited into the Late Payment Account in accordance with Section 4 of the ISO New England Billing Policy.

f) *Payment Default Shortfall Fund.* To the extent that the procedures described in clauses (b), (c), (d) and (e) above are insufficient to effect payment of the Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) the ISO will draw on the Shortfall Funding Arrangement to the extent the Shortfall Funding Arrangement is available at the time, and to the extent the Shortfall Funding Arrangement is not available at the time, the ISO will withdraw from the Payment Default Shortfall Fund, an amount equal to such unpaid Default Amount and shall apply such amount to the shortfall in Payments resulting from the Default Amount not being paid. To the extent that the amount on deposit in the Payment Default Shortfall Fund on any date is insufficient to pay all Unsecured Default Amounts, Uncovered Default Amounts, Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined below) on that date (after applying all amounts in the Late Payment Account for defaults on ISO Charges and all amounts in the Transmission Late Payment Account for defaults on Transmission Charges on that date), the amount in the Payment Default Shortfall Fund on that date shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts and all Unsecured Default Amounts, then such amount shall be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, Unsecured Default Amounts and Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts, total Unsecured Default Amounts, total Uncovered Transmission Default

Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts drawn on the Shortfall Funding Arrangement and/or withdrawn from the Payment Default Shortfall Fund and applied to any shortfall resulting from the Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Default Amount. If and to the extent that a Default Amount which is paid through a draw on the Shortfall Funding Arrangement and/or through a withdrawal from the Payment Default Shortfall Fund, interest on such a Default Amount and/or late charges with respect to such a Default Amount are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the Covered Entity), such amounts shall be paid to certain of the Covered Entities as set forth in Section 5.4 below.

g) *Congestion Revenue Fund*. If during any billing period congestion payments exceed congestion charges under Manual 28 (hereinafter a "Congestion Shortfall"), such that there is a shortfall in the total settlement for that week due to congestion, the ISO will draw from the Congestion Revenue Fund established and funded under Manual 28 to make up for the shortfall. To the extent there are insufficient funds in the Congestion Revenue Fund to cover that Congestion Shortfall, the ISO will recover the uncovered Congestion Shortfall pursuant to the allocation process set forth in Manual 28, Section 6. The ISO will true-up amounts drawn for Congestion Shortfalls on a monthly basis and reflect that true-up in the Statements reflecting Non-Hourly Charges.

h) Reduction of Payments and Increases in Charges for Unsecured Municipal Market Participants

(i) If and to the extent that (A) the defaulting Covered Entity is a Municipal Market Participant (as defined in the ISO New England Financial Assurance Policy) with a Market Credit Limit or a Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy (an "Unsecured Municipal Market Participant") and (B) the procedures described in clauses (b), (c), (d), (e), (f) and (g) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to

NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Municipal Market Participants owed monies for ISO Charges for the billing period to which the payment default relates (the "Default Period"), pro rata based on the ISO Charges owed to those Unsecured Municipal Market Participants, to the extent necessary to clear its accounts for ISO Charges due to Unsecured Municipal Market Participants by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.3(h)(i) shall not exceed the defaulting Unsecured Municipal Market Participant's Market Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Municipal Default Amount"). As funds attributable to an Unsecured Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Default Amount, shall be distributed pro rata to the Unsecured Municipal Market Participants that did not receive the full amount of their Payments as a result of such Unsecured Municipal Default Amount not being paid, up to the full amount that such Unsecured Municipal Market Participants did not receive as a result of such Unsecured Municipal Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Municipal Default Amount remains unpaid to Unsecured Municipal Market Participants on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Unsecured Municipal Default Amount remaining unpaid shall be reallocated among all of the Unsecured Municipal Market Participants receiving Statements for ISO charges for the Default Period (other than the Unsecured Municipal Market Participant defaulting on its payment obligations), pro rata based, for each Unsecured Municipal Market Participant being allocated

a share of the Unsecured Municipal Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Unsecured Municipal Market Participant that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Unsecured Municipal Market Participant that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Municipal Market Participant with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and an Unsecured Municipal Market Participant with $1,000 of Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Unsecured Municipal Default Amount under this clause (h)(ii). Each Unsecured Municipal Market Participant that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Unsecured Municipal Default Amount remaining unpaid under this clause (h)(ii). As funds attributable to an Unsecured Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Default Amount, shall be distributed to the Unsecured Municipal Market Participants pro rata based on their allocation of the Unsecured Municipal Default Amount under this clause (h)(ii), up to the full amount of such Unsecured Municipal Default Amount allocated to each such Unsecured Municipal Market Participant, with interest thereon.

(iii) An Unsecured Municipal Market Participant will not be allocated any Unsecured Municipal Default Amounts under this Section 3.3(h) for any Default Period if, at the start of the calendar year in which the applicable Default Period occurred, that Unsecured Municipal Market Participant provided the ISO with a written request to opt out of that allocation of Unsecured Municipal Default Amounts and that Unsecured Municipal Market Participant provides the ISO with additional financial assurance in the full amount of all of its "Financial Assurance

Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

i) *Reduction of Payments and Increases in Charges for Unsecured Non-Municipal Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity (x) is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and (y) has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy (each such Covered Entity being referred to herein as an "Unsecured Non-Municipal Covered Entity") and (B) the procedures described in clauses (b), (c), (d), (e), (f), and (g) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Non-Municipal Covered Entities owed monies for ISO Charges for the applicable Default Period, pro rata based on the ISO Charges owed to those Unsecured Non-Municipal Covered Entities, to the extent necessary to clear its accounts for ISO Charges due to Unsecured Non-Municipal Covered Entities by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.3(i)(i) shall not exceed the defaulting Unsecured Non-Municipal Covered Entity's Market Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Non-Municipal Default Amount"). As funds attributable to an Unsecured Non-Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Default Amount, shall be distributed pro rata to the Unsecured Non-Municipal Covered

Entities that did not receive the full amount of their Payments as a result of such Unsecured Non-Municipal Default Amount not being paid, up to the full amount that such Unsecured Non-Municipal Covered Entities did not receive as a result of such Unsecured Non-Municipal Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Non-Municipal Default Amount remains unpaid to Unsecured Non-Municipal Covered Entities on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Unsecured Non-Municipal Default Amount remaining unpaid shall be reallocated among all of the Unsecured Non-Municipal Covered Entities receiving Statements for ISO Charges for the Default Period (other than the Unsecured Non-Municipal Covered Entity defaulting on its payment obligations), pro rata based, for each Unsecured Non-Municipal Covered Entity being allocated a share of the Unsecured Non-Municipal Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Unsecured Non-Municipal Covered Entity that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Unsecured Non-Municipal Covered Entity that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Non-Municipal Covered Entity with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and an Unsecured Non-Municipal Covered Entity with $1,000 of Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Unsecured Non-Municipal Default Amount under this clause (i)(ii). Each Unsecured Non-Municipal Covered Entity that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Unsecured Non-Municipal Default Amount remaining unpaid under this clause (i)(ii). As funds attributable to an Unsecured Non-Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after

such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Default Amount, shall be distributed to the Unsecured Non-Municipal Covered Entities pro rata based on their allocation of the Unsecured Non-Municipal Default Amount under this clause (i)(ii), up to the full amount of such Unsecured Non-Municipal Default Amount allocated to each such Unsecured Non-Municipal Covered Entity, with interest thereon.

(iii) An Unsecured Non-Municipal Covered Entity will not be allocated any Unsecured Non-Municipal Default Amounts under this Section 3.3(i) for any Default Period if, at the start of the calendar year in which the applicable Default Period occurred, that Unsecured Non-Municipal Covered Entity provided the ISO with a written request to opt out of that allocation of Unsecured Non-Municipal Default Amounts and that Unsecured Non-Municipal Covered Entity provides the ISO with additional financial assurance in the full amount of all of its "Financial Assurance Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

j) *Reduction of Payments and Increase in Charges for Other Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity is not an Unsecured Municipal Market Participant or an Unsecured Non-Municipal Covered Entity (referred to together herein as an "Unsecured Covered Entity") or the Default Amount exceeds the Unsecured Municipal Default Amount or the Unsecured Non-Municipal Default Amount (referred to together herein as the "Unsecured Default Amount") for that Covered Entity and (B) the procedures described in clauses (b), (c), (d), (e), (f), (g), and (h) or (i) (if applicable) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to those Covered Entities owed monies for ISO Charges for that Default Period, pro rata based on the amounts owed to all Covered Entities, to the extent necessary to clear its accounts for ISO Charges by the close of banking

business on the date such Payments are due (after giving effect to clause (h) or (i) above if applicable) (the amount of such reduction in Payments for ISO Charges after giving effect to clause (h) or (i) above (if applicable) is referred to herein as the "Uncovered Default Amount"). For the avoidance of doubt, the Uncovered Default Amount is equal to the Default Amount minus any Unsecured Default Amount. As funds attributable to an Uncovered Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Default Amount, shall be distributed pro rata to the Covered Entities that did not receive the full amount of their Payments as a result of such Uncovered Default Amount not being paid, up to the full amount that such Covered Entities did not receive as a result of such Uncovered Default Amount not being paid, with interest thereon.

(ii) To the extent that any amount of an Uncovered Default Amount remains unpaid to Covered Entities on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Uncovered Default Amount remaining unpaid shall be reallocated among all of the Covered Entities receiving Statements for ISO Charges for the Default Period (other than the Covered Entity defaulting on its payment obligations), pro rata based, for each Covered Entity being allocated a share of the Uncovered Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Covered Entity that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Covered Entity that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, a Covered Entity with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and a Covered Entity with $1,000 of ISO Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Uncovered Default Amount under this clause (j)(ii). Each Covered Entity that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately

following the Default Period adjusted as necessary to reflect its obligation for the Uncovered Default Amount remaining unpaid under this clause (j)(ii). As funds attributable to an Uncovered Default Amount are received by the ISO (including amounts received through financial assurance provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Uncovered Default Amount, shall be distributed to the Covered Entities pro rata based on their allocation of the Uncovered Default Amount under this clause (j) (ii), up to the full amount of such Uncovered Default Amount allocated to each such Covered Entity, with interest thereon.

k) *Order of Settlement*. As amounts on Default Amounts are received by the ISO, the oldest outstanding ISO Charges will be settled first in the order of the creation of such debts.

l) Notwithstanding the other provisions of this Section 3.3, an unpaid amount shall not be considered a "Default Amount," and the ISO will not take any of the actions described in the suspension provisions of the ISO New England Financial Assurance Policy or in this Section 3.3 with respect to that unpaid amount, if the total unpaid amount is attributable to Qualification Process Cost Reimbursement Deposits (including any annual true-up of those amounts) and/or NEPOOL GIS API Fees. To the extent that a Covered Entity or a NEPOOL Participant pays only a part of an Invoice that includes a Charge for a Qualification Process Cost Reimbursement Deposit and/or a Charge for NEPOOL GIS API Fees, the unpaid amount shall first be allocated to the unpaid NEPOOL GIS API Fees, and then to that Qualification Process Cost Reimbursement Deposit, and other Charges on that Invoice will only be considered not to have been paid if the unpaid amount exceeds the amount of the Qualification Process Cost Reimbursement Deposit and any unpaid NEPOOL GIS API Fees. The sole consequence of a Covered Entity's or a NEPOOL Participant's failure to pay NEPOOL GIS API Fees, after application of any set-off rights against the Covered Entity or NEPOOL Participant and any financial assurance provided by that Covered Entity or NEPOOL Participant, shall be denial to that Covered Entity or NEPOOL

Participant of access to any application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

Section 3.4 – Payment Default for Transmission Charges. If the ISO, in its reasonable opinion, believes that all or any part of any amount of Transmission Charges due to be paid to the ISO by any Covered Entity will not or has not been paid when due (the "Transmission Default Amount"), then the following procedures shall apply:

a) *Use of Set-Offs*. The ISO shall use any and all rights of set-off it has under the Governing Documents, including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, against a defaulting Covered Entity with respect to Transmission Charges due to that Covered Entity to the extent necessary to pay the Default Amount, together with any interest accrued thereon and any late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, due from such Covered Entity.

b) *Enforcing the Security of a Defaulting Party*. If and to the extent that the procedure described in clause (a) above is insufficient to effect payment of the Transmission Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall use the financial assurance(s) provided by the defaulting Covered Entity under the ISO New England Financial Assurance Policy to the extent necessary to pay the Transmission Default Amount and such interest and late charges. Any use of financial assurance(s) shall be undertaken in compliance with the ISO New England Financial Assurance Policy.

c) *Action Against a Defaulting Party*. If and to the extent that the procedures described in clauses (a) and (b) above are insufficient to effect payment of the Transmission Default Amount and all interest accrued theron and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall take appropriate actions to recover the Transmission Default Amount and such accrued interest and late charges, which

actions may include, without limitation, initiating proceedings in accordance with the appropriate dispute resolution mechanisms or actions with Covered Entities or before the Commission or a court of competent jurisdiction against the defaulting Covered Entity. Before initiating any such proceedings, the ISO shall consult with the Chair of the NEPOOL Budget and Finance Subcommittee or NEPOOL counsel. Any amounts incurred by the ISO or any Market Participant in connection with any such action or proceeding shall be paid by the defaulting Covered Entity.

d) *Transmission Late Payment Account*. If and to the extent that the procedures described in clauses (a), (b) and (c) above are insufficient to effect payment of the Transmission Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) by the time the corresponding Payment to the Covered Entities is due, the ISO shall withdraw from the Transmission Late Payment Account, as that term is defined in Section 4 of the ISO New England Billing Policy, an amount equal to such unpaid Transmission Default Amount, to the extent that such amount is available in the Transmission Late Payment Account, and shall apply such amount to any shortfall in Payments resulting from the Transmission Default Amount not being paid. To the extent that the amount on deposit in the Transmission Late Payment Account on any date is insufficient to pay all Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined below) on that date, the amount in the Transmission Late Payment Account shall first be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts withdrawn from the Transmission Late Payment Account and applied toward any shortfall resulting from the Transmission Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Transmission Default Amount. If and to the extent that such Transmission Default Amount, interest thereon and/or late charges with respect thereto are subsequently collected (including as a result

of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the defaulting Covered Entity), such amounts shall first be used to pay Covered Entities for the amount of such Transmission Default Amount allocated to them under clause (f), (g) and (h) below, with interest thereon, and then, after all such amounts have been paid to Covered Entities, such Transmission Default Amount, interest and/or late charges shall be deposited into the Transmission Late Payment Account in accordance with Section 4 of the ISO New England Billing Policy.

e) *Payment Default Shortfall Fund* To the extent that the procedures described in clauses (a), (b), (c) and (d) above are insufficient to effect payment of the Transmission Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy), the ISO will draw on the Shortfall Funding Arrangement to the extent the Shortfall Funding Arrangement is available at the time, and to the extent the Shortfall Funding Arrangement is not available at the time, the ISO will withdraw from the Payment Default Shortfall Fund, an amount equal to such unpaid Transmission Default Amount and shall apply such amount to the shortfall in Payments resulting from the Transmission Default Amount not being paid. To the extent that the amount on deposit in the Payment Default Shortfall Fund on any date is insufficient to pay all Unsecured Default Amounts, Uncovered Default Amounts, Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined herein) on that date (after applying all amounts in the Late Payment Account for defaults on ISO Charges and all amounts in the Transmission Late Payment Account for defaults on Transmission Charges on that date), the amount in the Payment Default Shortfall Fund on that date shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts and all Unsecured Default Amounts, then such amount shall be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, Unsecured Default Amounts and Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured

Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts, total Unsecured Default Amounts, total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts drawn on the Shortfall Funding Arrangement and/or withdrawn from the Payment Default Shortfall Fund and applied to any shortfall resulting from the Transmission Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Transmission Default Amount. If and to the extent that a Transmission Default Amount which is paid through a draw on the Shortfall Funding Arrangement and/or through a withdrawal from the Payment Default Shortfall Fund, interest on such a Transmission Default Amount and/or late charges with respect to such a Transmission Default Amount are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the Covered Entity), such amounts shall be paid to certain of the Covered Entities as set forth in Section 5.4 below.

f) *Reduction of Payments and Increases in Transmission Charges for Unsecured Municipal Market Participants.*

(i) If and to the extent that (A) the defaulting Covered Entity is an Unsecured Municipal Market Participant and (B) the procedures described in clauses (a), (b), (c), (d), and (e) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Municipal Market Participants owed monies for Transmission Charges for that billing period (the "Transmission Default Period"), pro rata based on the Transmission Charges owed to those Unsecured Municipal Market Participants, to the extent necessary to clear its accounts for Transmission Charges due to Unsecured Municipal Market Participants by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.4(f) shall not exceed the defaulting Unsecured Municipal Market Participant's Transmission Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Municipal Transmission Default Amount"). As funds

attributable to an Unsecured Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Transmission Default Amount, shall be distributed pro rata to the Unsecured Municipal Market Participants that did not receive the full amount of their Payments as a result of such Unsecured Municipal Transmission Default Amount not being paid, up to the full amount that such Unsecured Municipal Market Participants did not receive as a result of such Unsecured Municipal Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Municipal Transmission Default Amount remains unpaid to Unsecured Municipal Market Participants on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Unsecured Municipal Transmission Default Amount remaining unpaid shall be reallocated among all of the Unsecured Municipal Market Participants receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Unsecured Municipal Market Participant defaulting on its payment obligations), pro rata based, for each Unsecured Municipal Market Participant being allocated a share of the Unsecured Municipal Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Unsecured Municipal Market Participant that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments for Transmission Charges due to such Unsecured Municipal Market participant that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Municipal Market Participant with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and an Unsecured Municipal Market Participant with $1,000 of Transmission Charges and $1,000 of Payments for Transmission Charges on its Transmission Statement for the

Transmission Default Period would be allocated an equal share of the unpaid Unsecured Municipal Transmission Default Amount under this clause (f)(ii). Each Unsecured Municipal Market Participant that received a Transmission Statement for the Transmission Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Unsecured Municipal Transmission Default Amount remaining unpaid under this clause (f)(ii). As funds attributable to an Unsecured Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Transmission Default Amount, shall be distributed to the Unsecured Municipal Market Participants pro rata based on their allocation of the Unsecured Municipal Transmission Default Amount under this clause (f)(ii), up to the full amount of such Unsecured Municipal Transmission Default Amount allocated to each such Unsecured Municipal Market Participant, with interest thereon.

(iii) An Unsecured Municipal Market Participant will not be allocated any Unsecured Municipal Transmission Default Amounts under this Section 3.4(f) for any Transmission Default Period if, at the start of the calendar year in which the applicable Transmission Default Period occurred, that Unsecured Municipal Market Participant provided the ISO with a written request to opt out of that allocation of Unsecured Municipal Transmission Default Amounts and that Unsecured Municipal Market Participant provides the ISO with additional financial assurance in the full amount of all of its "Transmission Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

g) *Reduction of Payments and Increases in Transmission Charges for Unsecured Non-Municipal Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity is an Unsecured Non-Municipal Covered Entity and (B) the procedures described in clauses (a), (b),

(c), (d), and (e) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Non-Municipal Covered Entities owed monies for the applicable Transmission Default Period, pro rata based on the Transmission Charges owed to those Unsecured Non-Municipal Covered Entities, to the extent necessary to clear its accounts for Transmission Charges due to Unsecured Non-Municipal Covered Entities by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.4(g) shall not exceed the defaulting Unsecured Non-Municipal Covered Entity's Transmission Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Non-Municipal Transmission Default Amount"). As funds attributable to an Unsecured Non-Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Transmission Default Amount, shall be distributed pro rata to the Unsecured Non-Municipal Covered Entities that did not receive the full amount of their Payments as a result of such Unsecured Non-Municipal Transmission Default Amount not being paid, up to the full amount that such Unsecured Non-Municipal Covered Entities did not receive as a result of such Unsecured Non-Municipal Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Non-Municipal Transmission Default Amount remains unpaid to Unsecured Non-Municipal Covered Entities on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Unsecured Non-Municipal Transmission Default Amount remaining unpaid shall be reallocated among all of the Unsecured Non-Municipal Covered Entities receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Unsecured Non-Municipal Covered Entity defaulting on its payment obligations), pro rata based, for each Unsecured Non-Municipal

Covered Entity being allocated a share of the Unsecured Non-Municipal Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Unsecured Non-Municipal Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments for Transmission Charges due to such Unsecured Non-Municipal Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Non-Municipal Covered Entity with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and an Unsecured Non-Municipal Covered Entity with $1,000 of Transmission Charges and $1,000 of Payments for Transmission Charges on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Unsecured Non-Municipal Transmission Default Amount under this clause (g)(ii). Each Unsecured Non-Municipal Covered Entity that received a Transmission Statement for the Transmission Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Unsecured Non-Municipal Transmission Default Amount remaining unpaid under this clause (g)(ii). As funds attributable to an Unsecured Non-Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Transmission Default Amount, shall be distributed to the Unsecured Non-Municipal Covered Entities pro rata based on their allocation of the Unsecured Non-Municipal Transmission Default Amount under this clause (g)(ii), up to the full amount of such Unsecured Non-Municipal Transmission Default Amount allocated to each such Unsecured Non-Municipal Covered Entity, with interest thereon.

(iii) An Unsecured Non-Municipal Covered Entity will not be allocated any Unsecured Non-Municipal Transmission Default Amounts under this Section 3.4(g) for any Transmission Default Period if, at the start of the calendar year in which the applicable Transmission Default Period occurred, that Unsecured Non-Municipal Covered Entity provided the ISO with a written request to opt out of that allocation of Unsecured Non-Municipal Transmission Default Amounts and that Unsecured Non-Municipal Covered Entity provides the ISO with additional financial assurance in the full amount of all of its "Transmission Obligations" under the ISO New England Financial Assurance Policy all times during that calendar year.

h) Reduction of Payments and Increases in Transmission Charges for Other Covered Entities.

(i) If and to the extent that (A) the defaulting Covered Entity is not an Unsecured Covered Entity or the Transmission Default Amount for that Covered Entity exceeds the Unsecured Municipal Transmission Default Amount or the Unsecured Non-Municipal Transmission Default Amount (referred to together herein as the "Unsecured Transmission Default Amount") for that Covered Entity and (B) the procedures described in clauses (a), (b), (c), (d), (e) and (f) or (g) (if applicable) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to those Covered Entities owed monies for Transmission Charges for that Transmission Default Period, pro rata based on the amounts owed to all Covered Entities, to the extent necessary to clear its accounts for Transmission Charges by the close of banking business on the date such Payments are due (after giving effect to clauses (f) and (g) above if applicable) (the amount of such reduction in Payments for Transmission Charges after giving effect to clauses (f) and (g) above (if applicable) is referred to herein as the "Uncovered Transmission Default Amount"). For the avoidance of doubt, the Uncovered Transmission Default Amount is equal to the Transmission Default Amount minus any Unsecured Transmission Default Amount. As funds attributable to an Uncovered Transmission Default Amount are received by the ISO (including amounts received through financial assurance provided under the ISO New England Financial Assurance Policy or through actions or proceedings

commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Transmission Default Amount, shall be distributed pro rata to the Covered Entities that did not receive the full amount of their Payments as a result of such Uncovered Transmission Default Amount not being paid, up to the full amount that such Covered Entities did not receive as a result of such Uncovered Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any amount of an Uncovered Transmission Default Amount remains unpaid to Covered Entities on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Uncovered Transmission Default Amount remaining unpaid shall be reallocated among all the Covered Entities receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Covered Entity defaulting on its payment obligations), pro rata based, for each Covered Entity being allocated a share of the Uncovered Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments due to such Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, a Covered Entity with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and a Covered Entity with $1,000 of Transmission Charges and $1,000 of Payments on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Uncovered Transmission Default Amount under this clause (h)(ii). Each Covered Entity that received a Transmission Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Uncovered Transmission Default Amount remaining unpaid under this clause (h)(ii). As funds attributable to an Uncovered Transmission Default Amount are received by the ISO

(including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Uncovered Transmission Default Amount, shall be distributed to the Covered Entities pro rata based on their allocation of the Uncovered Transmission Default Amount under this clause (h)(ii), up to the full amount of such Uncovered Transmission Default Amount allocated to each such Covered Entity, with interest thereon.

i) *Order of Settlement.*

As amounts on Transmission Default Amounts are received by the ISO, the oldest outstanding Transmission Charges will be settled first in the order of the creation of such debts.

Section 3.5 -Enforcement of Payment Obligations Against Defaulting Covered Entities. Each Covered Entity that shared in any shortfall in payments under Section 3.3 or Section 3.4 shall have an independent right to seek and obtain payment and recovery of the amount of its share of such shortfall (the "Allocated Assessment") from the defaulting Covered Entity. Each Covered Entity consents to other Covered Entities' having this independent right. Any Covered Entity that recovers any portion of its Allocated Assessment from a defaulting Covered Entity shall promptly so notify the ISO, and such Covered Entity's share of any recovery of a shortfall in payments hereunder shall be reduced by the amount of its Allocated Assessment that it recovers on its own. In addition to any amounts in default, the defaulting Covered Entity shall be liable to the ISO and each other Covered Entity for all reasonable costs incurred in enforcing the defaulting Covered Entity's obligations.

Section 3.6 – Set-Off. The ISO shall apply any amount to which any defaulting Covered Entity is or will be entitled for ISO Charges or Transmission Charges toward the satisfaction of any of that defaulting Covered Entity's debts to NEPOOL or to the ISO for ISO Charges or Transmission Charges which are incurred under the Governing Documents, including the ISO New England Financial Assurance Policy; provided that amounts due for ISO Charges will first be applied to ISO Charges then, to the extent of any excess, to Transmission Charges, and amounts due for

Transmission Charges will be first applied to Transmission Charges then, to the extent of any excess, to ISO Charges.

Section 3.7 – Notice and Suspension. Without limiting any of the other remedies described above, in the event that the ISO, in its reasonable opinion, believes that all or any part of any amount due to be paid by any Covered Entity for ISO Charges (other than NEPOOL GIS API Fees) or Transmission Charges will not be or has not been paid when due, the ISO (on its own behalf or on behalf of the Covered Entities) may (but shall not be required to) notify such Covered Entity in writing, electronically and by first class mail sent in each case to such Covered Entity's billing contact, of such payment default. If a payment default (other than a payment default relating solely to NEPOOL GIS API Fees) is not cured by 10:00 a.m. Eastern Time on the Business Day immediately following the Business Day when such payment was originally due, the ISO shall notify such Market Participant, the NEPOOL Budget and Finance Subcommittee, all members and alternates of the Participants Committee, the New England governors and utility regulatory agencies and the credit and billing contacts for all Market Participants of (i) the identity of the Covered Entity receiving such notice, (ii) whether such notice relates to a payment default, (iii) whether the defaulting Covered Entity has a registered load asset, and (iv) the actions the ISO plans to take and/or has taken in response to such payment default. In addition, the ISO will provide any additional information with respect to such payment default as may be required under the ISO New England Information Policy. If a payment default (other than a payment default relating solely to NEPOOL GIS API Fees) is not cured by 8:30 a.m., Eastern Time, of the second Business Day after the date when such payment was originally due, the defaulting Covered Entity shall be suspended pursuant to the suspension provisions of the ISO New England Financial Assurance Policy (which will apply to the defaulting Covered Entity regardless of whether it is a "Municipal Market Participant" or a "Non-Municipal Market Participant" under the ISO New England Financial Assurance Policy). Such defaulting Covered Entity shall be suspended as described in the ISO New England Financial Assurance Policy until such payment default has been cured in full. If the ISO has issued a notice that a Covered Entity has defaulted on a payment obligation and that Covered Entity subsequently cures that payment default, such Covered Entity may request the ISO to issue a notice stating such fact; provided, however, that the ISO shall not be required to issue that notice unless, in its sole discretion, the ISO determines that such payment default has been cured and such Covered Entity has no other outstanding payment defaults.

If either (x) a Covered Entity is suspended from the New England Markets as a result of a payment default as described in this Section 3.7 as a result of a payment default involving ISO Charges or (y) a Covered Entity receives more than five notices of payment defaults with respect to ISO Charges in any rolling 12-month period, then such Covered Entity shall pay a $1,000 penalty for such suspension and for each notice after the fifth notice in a rolling 12-month period. All penalties paid under this paragraph shall be deposited in the Late Payment Account.

Section 3.8– Bankruptcy Filings. In the event any Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor (the "Bankruptcy Event") and the ISO is required to return any payments made by such Covered Entity to the bankruptcy court having jurisdiction over such Bankruptcy Event, the ISO may avail itself of any emergency funding provisions in the Transmission, Markets and Services Tariff to collect the amounts returned by the ISO.

Section 3.9 – Partial Payments of Combined Invoices. If ISO Charges and Transmission Charges are included on the same Invoice and the Covered Entity pays only a portion of the Charges included in that Invoice, then the ISO shall use monies received by it from that Covered Entity (i) first to pay all amounts due from that Covered Entity to the ISO under Section IV of the Transmission, Markets and Services Tariff, to NEPOOL for Participant Expenses, and to the ISO for acting as Project Manager for the NEPOOL GIS before making any payments to any Covered Entities, then (ii) then to pay all amounts due for that Covered Entity's share, if any, of the amounts due to the NEPOOL GIS Administrator (other than NEPOOL GIS API Fees), (iii) then to pay all amounts due from that Covered Entity with respect to the Shortfall Funding Arrangement, and (iv) then, to the extent of any remaining amounts received from that Covered Entity, those amounts will be allocated to the ISO Charges and Transmission Charges on that Invoice pro rata based on the total amount of each set of Charges on that Invoice, subject to Section 3.3(l) with respect to Charges for Qualification Process Cost Reimbursement Deposits and/or Charges for NEPOOL GIS API Fees. Notwithstanding the foregoing, a partial payment of any Invoice shall be a payment default.

3.10 – Sharing of Financial Assurance. If the financial assurance(s) provided by a Covered Entity under the ISO New England Financial Assurance Policy are insufficient to effect payment of all ISO Charges and Transmission Charges that are due on the same date and which have not been

paid by that Covered Entity, the ISO shall allocate the amounts available under those financial assurance(s) as follows:

i. first to pay all amounts due from that Covered Entity to the ISO under Section IV of the Transmission, Markets and Services Tariff, to NEPOOL for Participant Expenses, and to the ISO for acting as Project Manager of the NEPOOL GIS;

ii. second, to pay all amounts due for that Covered Entity's share, if any, of the amounts due to the NEPOOL GIS Administrator (other than NEPOOL GIS API Fees);

iii. third, to pay all amounts due from that Covered Entity with respect to the Shortfall Funding Arrangement;

iv. fourth, to the Covered Entity's Charges for FTR transactions, up to the FTR Financial Assurance Requirements calculated for that Covered Entity by the ISO on the last day of the billing period for which the payment default has occurred; and

v. fifth, to the remaining unpaid ISO Charges and the unpaid Transmission Charges owed by that Covered Entity pro rata based on the total amount of each set of Charges due, subject to Section 3.3(l) with respect to Charges for Qualification Process Cost Reimbursement Deposits and/or Charges for NEPOOL GIS API Fees.

Section 3.11 – Allocation of Payment Defaults to Other Groups. In some cases, the Default Amount or the Transmission Default Amount may exceed the amounts owed to the specified Covered Entities that are to receive less than the full Payments due to them pursuant to Section 3.3(h)(i), Section 3.3(i)(i), Section 3.4(f)(i) or Section 3.4(g)(i). In such an event, the ISO will reduce the Payments due to Covered Entities pursuant to Section 3.3(j)(i) (for ISO Charges) or Section 3.4(h)(i) (for Transmission Charges) to the extent necessary for the ISO to clear its accounts for ISO Charges or Transmission Charges by the close of banking business on the date the applicable Payments are due. Any amount allocated to Covered Entities under the preceding sentence will be invoiced to and collected from the appropriate Covered Entities under Section

3.3(h)(ii), Section 3.3(i)(ii), Section 3.4(f)(ii) or Section 3.4(g)(ii) in the billing period immediately following the billing period in which that allocation occurred.

Section 3.12 – Other Rights Against Defaulting Parties. Nothing set forth in the ISO New England Billing Policy shall nullify, restrict or otherwise limit the rights and remedies of the ISO, NEPOOL and the Covered Entities against a defaulting Covered Entity that are set forth in the Governing Documents, including the ISO New England Financial Assurance Policy or otherwise, including without limitation any late payment charges or rights to terminate or limit trading rights of the defaulting Covered Entity, to the extent such rights and remedies otherwise exist.

SECTION 4 – LATE PAYMENT CHARGE; LATE PAYMENT ACCOUNT

Section 4.1 -Late Payment Charge.

(a) If a Covered Entity is delinquent two or more times within any period of 12 months in paying on time its ISO Charges, such Covered Entity shall pay, in addition to interest on each such late payment, a late payment charge for its second failure to pay on time, and for each subsequent failure to pay on time within the same 12-month period (a "Late Payment Charge") in an amount equal to the greater of (i) two percent (2%) of the total amount of such late payment or (ii) $500.00. In the case of a former Market Participant that applies again for membership in the ISO, a determination of delinquency shall be based on the Market Participant's history of payment of its ISO Charges in its last 12 months of membership.

(b) If a Covered Entity is delinquent two or more times within any period of 12 months in paying on time its Transmission Charges, such Covered Entity shall pay, in addition to interest on each such late payment, a late payment charge for its second failure to pay on time, and for each subsequent failure to pay on time within the same 12-month period (a "Transmission Late Payment Charge") in an amount equal to the greater of (i) two percent (2%) of the total amount of such late payment or (ii) $500.00. In the case of a former Market Participant that applies again for membership in the ISO, a determination of delinquency shall be

based on the Market Participant's history of payment of its Transmission Charges in its last 12 months of membership.

Section 4.2 -Late Payment Account; Transmission Late Payment Account.

(a) Interest collected on late payments of ISO Charges shall be allocated and paid to the Covered Entities to whom such late payments are due, pro rata in accordance with the amount due to each such Covered Entity. Late Payment Charges that are collected and not distributed to the Covered Entities under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy shall be deposited by the ISO into a segregated interest-bearing account (the "Late Payment Account") for disbursement in accordance with Section 3.3 of the ISO New England Billing Policy; provided, however, that in no event shall the amount in the Late Payment Account, including interest accrued thereon, at any time exceed $1,000,000 or other amount determined from time to time by the Participants Committee (the "Late Payment Account Limit"). Any amount in the Late Payment Account (including interest thereon) in excess of the Late Payment Account Limit shall be distributed to the Market Participants, no more frequently than quarterly, pro rata based on their ISO Charges in the month preceding the month in which such distribution is to be made; provided, however that no amount from the Late Payment Account shall be distributed to any Market Participant in payment default at the time of such distribution.

(b) Interest collected on late payments of Transmission Charges shall be allocated and paid to the Covered Entities to whom such late payments are due, pro rata in accordance with the amount due to each such Covered Entity. Transmission Late Payment Charges that are collected and not distributed to the Covered Entities under the ISO New England Billing Policy shall be deposited by the ISO into a segregated interest-bearing account (the "Transmission Late Payment Account") for disbursement in accordance with Section 3.4 of the ISO New England Billing Policy; provided, however, that in no event shall the amount in the Transmission Late Payment Account, including interest accrued thereon, at any time exceed $1,000,000 or other amount determined from time to time by the Participants

Committee (the "Transmission Late Payment Account Limit"). Any amount in the Transmission Late Payment Account (including interest thereon) in excess of the Transmission Late Payment Account Limit shall be distributed to the Market Participants, no more frequently than quarterly, pro rata based on their Transmission Charges in the month preceding the month in which such distribution is to be made; provided, however that no amount from the Transmission Late Payment Account shall be distributed to any Market Participant in payment default at the time of such distribution.

SECTION 5 – SHORTFALL FUNDING ARRANGEMENTS: PAYMENT DEFAULT SHORTFALL FUND

Section 5.1 – Purpose and Creation of the Shortfall Funding Arrangement and the Payment Default Shortfall Fund. The ISO, acting in consultation with the NEPOOL Budget and Finance Subcommittee and NEPOOL's Independent Financial Advisor, will arrange separate financing (the "Shortfall Funding Arrangement") that can be used to make up any non-congestion related differences between ISO Charges received on Invoices and amounts due for ISO Charges in any week and as set forth in Sections 3.3 and 3.4. The Shortfall Funding Arrangement may be effected through third-party financing, through the creation of a special purpose funding entity, through Participant-provided funds or through some other arrangement agreed upon by the ISO, the NEPOOL Budget and Finance Subcommittee and NEPOOL's Independent Financial Advisor. If and to the extent that, at any time, the Shortfall Funding Arrangement is not available (because, solely for example, it has not been arranged, it does not have sufficient funds available, it has expired or it has been terminated prior to its maturity), the ISO shall create a Payment Default Shortfall Fund that will provide for such non-congestion related difference between ISO Charges received on Invoices and amounts due for ISO Charges in any week and for payments in accordance with Section 3.3 and 3.4. The Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund shall be in addition to and not a replacement for the Late Payment Account or the Transmission Late Payment Account described above.

Section 5.2 -Participant Rights with respect to a Participant Financial Payment Default Shortfall Fund. To the extent that the Payment Default Shortfall Fund is in existence at any time, each Participant funding the Payment Default Shortfall Fund at such time would retain title to its share of amounts in the Payment Default Shortfall Fund and any interest accrued on those amounts on a

pro rata basis based on the funds in the Payment Default Shortfall Fund provided by it. Each Participant will receive a monthly report that will identify the amount of funds in the Payment Default Shortfall Fund that belong to that Participant and the amount of interest accrued thereon. As Participants withdraw from or otherwise terminate membership in the ISO, the ISO would pay to such Participants their share, if any, of the amounts in the Payment Default Shortfall Fund, with interest. To the extent that the balance in the Payment Default Shortfall Fund exceeds the Required Balance, the excess will be refunded to Participants on a quarterly basis pro rata based on their share of the funds in the Payment Default Shortfall Fund.

Section 5.3 – Available Amount of Shortfall Funding Arrangement; Initial Funding of the Payment Default Shortfall Fund. The available amount of the Shortfall Funding Arrangement, combined with any amount on deposit in the Payment Default Shortfall Fund, shall be equal to the amount of a hypothetical Invoice at the 97th percentile of the average amounts due on Invoices rendered to Market Participants over the six calendar months preceding the calculation or a lesser amount as set by the ISO from time to time in consultation with the NEPOOL Budget and Finance Subcommittee (the "Required Balance"), which amount shall be calculated and adjusted by the ISO on a quarterly basis. To the extent that on any Business Day immediately following the date on which Payments for Non-Hourly Charges are due, either the Shortfall Funding Arrangement has not been established or the available amount of the Shortfall Funding Arrangement is less than the Required Balance, the ISO shall establish the Payment Default Shortfall Fund, and the Participants shall be responsible for initially funding the Payment Default Shortfall Fund in an amount equal to the Required Balance less the available amount, if any, of the Shortfall Funding Arrangement on such date (the "Participant Required Balance"). The ISO, in consultation with NEPOOL's Independent Financial Advisor, shall notify the Market Participants promptly if they believe that the available amount of the Shortfall Funding Arrangement is not, or is reasonably likely not to be, at least equal to the Required Balance, and the ISO will endeavor to arrange a supplement to any existing Shortfall Funding Arrangement at least to the extent required to fund such shortfall. The Market Participant Required Balance shall initially be funded by the Market Participants pro rata in accordance with the methodology used for the shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on Charges and Payments due over the three months immediately preceding the establishment of the Payment Default Shortfall Fund). A Participant's Payment Default Shortfall Fund payment obligation shall be identified as a separate line item on its Statements and Transmission Statements.

Section 5.4 Continued Shortfall Fund Funding Obligations; Payments on Shortfall Funding Arrangement.

(a) The ISO will reallocate the Market Participants' overall obligation with respect to the amounts in the Payment Default Shortfall Fund, if any, annually on each anniversary of the Effective Date in accordance with the methodology used for shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on the Charges and Payment due in the preceding calendar year), with payments from and refunds to Market Participants that have underfunded or overfunded, respectively, the Payment Default Shortfall Fund based on that annual reallocation.

(b) If the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund (the "Total Available Amount") drops below 90 percent of the Required Balance at any time because of Market Participant terminations (but not because of draws on the Shortfall Funding Arrangement or the Payment Default Shortfall Fund or adjustments to the Required Balance), each Market Participant would be required to contribute a share of the funds needed to restore the Total Available Amount to the Required Balance. A Market Participant's pro rata share of that obligation would be determined in accordance with the methodology used for shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on Charges and Payments due for the three months immediately preceding the date of that funding).

(c) If (i) the ISO draws on the Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund and the amount drawn, together with interest and fees thereon, is not replaced through payments on the payment default by the date on which the ISO next issues an Invoice that includes Non-Hourly Charges, or (ii) the Required Balance is increased as a result of quarterly adjustments, that next Invoice for Non-Hourly Charges will include a charge for Covered Entities necessary to restore the Total Available Amount to the Required Balance. That charge will be allocated among the Covered Entities according to the methodology used for the shortfall allocation process in Section 3.3(j)(ii) and

Section 3.4(h)(ii) of the ISO New England Billing Policy with respect to the specific payment default. If payments on a payment default are received after the amount drawn from the Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund for that payment default has been refunded, the amount of the payment default so received shall be allocated and paid to the Covered Entities providing that funding according to the methodology of Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy.

(d) In addition to the other obligations described in this Section 5.4, each Market Participant shall be charged a pro rata share of all interest, fees and other expenses incurred in connection with the Shortfall Funding Arrangement to the extent that such interest, fees and expenses are not paid by a Covered Entity with respect to a payment default. The pro rata allocation of fees and expenses described herein shall be made on the same basis as set forth in Section 5.4(c) above. A Market Participant's obligation with respect to the Shortfall Funding Arrangement shall be identified as a separate line item on its statements.

(e) Without limiting the generality of Section 3.3 and Section 3.4, to the extent that a Covered Entity fails to pay an Invoice, requiring a draw on the Shortfall Funding Arrangement, that Covered Entity shall be required to pay the amount of such draw, plus any interest accrued thereon and premium or other fees or expenses with respect thereto.

Section 5.5 -Payment Default Shortfall Fund Account. Funds collected as Market Participant contributions to the Payment Default Shortfall Fund shall be deposited by the ISO into a segregated interest-bearing account.

SECTION 6 -BILLING DISPUTE PROCEDURES.

Section 6.1 -Requested Billing Adjustments Eligible for Resolution under Billing Dispute Procedures. Any Covered Entity may dispute the amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice (a "Disputed Amount"). Such party (a "Disputing Party") shall seek to recover such Disputed Amount, including accrued interest, pursuant to this Section 6, by first submitting a request for billing adjustment to the ISO

(a "Requested Billing Adjustment" or "RBA") in accordance with the procedures provided in this Section 6. A Disputing Party may seek resolution of a Requested Billing Adjustment under this Section 6 concerning any Disputed Amount resulting from the determination of a market clearing price or Transmission, Markets and Services Tariff rate by the ISO that allegedly either violates or is otherwise inconsistent with the Transmission, Markets and Services Tariff, or results from error by the ISO, and provided that a request for a correction of a Meter Data Error shall not be considered a Requested Billing Adjustment for purposes of the ISO New England Billing Policy, and requests for corrections of Meter Data Errors will be handled exclusively through the procedures set out in Market Rule 1. Notwithstanding the foregoing, a Requested Billing Adjustment must involve a requested change in an amount owed or believed to be owed in a Remittance Advice that is not covered by another alternative dispute resolution procedure under the Transmission, Markets and Services Tariff. Furthermore, a Requested Billing Adjustment must not involve Disputed Amounts paid on an Invoice for Non-Hourly Charges pursuant to the ISO New England Financial Assurance Policy, provided, however, that this provision shall not preclude a Disputing Party from submitting a Requested Billing Adjustment for a Disputed Amount on a fully paid monthly Invoice for Non-Hourly Charges which has been paid pursuant to an Invoice for Non-Hourly Charges in that month.

Section 6.2 -Effect of the ISO New England Billing Policy on Rights of Market Participant, PTO, or Non-Market Participant Transmission Customer with Respect to a Disputed Amount. Except as otherwise set forth in this Section 6.2, nothing in this Section 6 shall in any way abridge the right of any Covered Entity to seek legal or equitable relief under the Federal Power Act and/or any other applicable laws with respect to any Disputed Amount. Prior to commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction to resolve the dispute which is the subject of the Requested Billing Adjustment, the Disputing Party must first submit the Requested Billing Adjustment to the ISO for review pursuant to Section 6.3 of the ISO New England Billing Policy.

Section 6.3 – ISO Review of Requested Billing Adjustment.

Section 6.3.1 – Submission of Requested Billing Adjustment to the ISO; Required Contents of Requested Billing Adjustment. A Disputing Party shall submit a Requested Billing Adjustment in writing to Participant Support and Solutions at the ISO via its support system. A Requested Billing Adjustment will be deemed received once an acknowledgement and/or a case number has

been assigned and transmitted to the Disputing Party. In its Requested Billing Adjustment, the Disputing Party must specify: (a) the Disputed Amount at issue, (b) the instance of alleged error at issue, including a statement detailing the specific provisions of all applicable governing documents that support the Requested Billing Adjustment, and (c) the specific person or persons to whom all communications to the Disputing Party regarding the Requested Billing Adjustment are to be addressed. A Disputing Party must submit its Requested Billing Adjustment within three months of the date that the Invoice or Remittance Advice containing the Disputed Amount was issued by the ISO unless the Disputing Party could not have reasonably known of the existence of the alleged error within such time.

Section 6.3.2 – Notice of ISO Review of Requested Billing Adjustment. Within three Business Days of the receipt ISO Participant Support and Solutions by of a Requested Billing Adjustment, 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 Requested Billing Adjustment ("Notice of RBA"), including, subject to the protection of Confidential Information, the specifics of the Requested Billing Adjustment. The Notice of RBA shall identify a specific representative of the ISO to whom all communications regarding the Requested Billing Adjustment are to be sent.

Section 6.3.3 – ISO Review of Requested Billing Adjustments. The ISO shall complete its review of a Requested Billing Adjustment received pursuant to Section 6.3 within twenty (20) Business Days of the date the ISO distributes the Notice of RBA. To the extent that either party makes such a request and both parties agree to such request, the ISO and Disputing Party may meet or otherwise confer during this period in an effort to resolve the Requested Billing Adjustment.

Section 6.3.4 – Comment Period. Any Covered Entity which desires to do so, or NEPOOL if it desires to do so, may submit to the ISO's designated representative, on or before the tenth (10th) Business Day following the date the ISO distributes the Notice of RBA, written comments to the ISO with respect to the Requested Billing Adjustment. Any such comments are to be transmitted simultaneously to the Disputing Party. The Disputing Party may respond to any such comments by submitting a written response to the ISO's designated representative and to the commenting party on or before the fifteenth (15th) Business Day following the date the ISO distributes the Notice of RBA. In determining the action it will take with respect to the Requested Billing Adjustment, the ISO shall consider the written response filed by the Disputing Party. The ISO

may but is not required to consider any written comments that are filed by any other interested party.

Section 6.3.5 – ISO Action on Requested Billing Adjustment. The ISO shall provide to the Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee a written decision (the "RBA Decision") accepting or denying a Requested Billing Adjustment received pursuant to this Section 6.3 within twenty (20) Business Days of the date the ISO distributes the Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO. The ISO shall provide written notice and a copy of each RBA Decision to each Covered Entity either eligible for reimbursement, denied reimbursement of a Disputed Amount or required to provide reimbursement of a Disputed Amount because of an RBA Decision (hereafter referred to as an "Affected Party" or the "Affected Parties") within five (5) Business Days of the date the RBA Decision is rendered. In providing such notice to any Affected Party required to provide reimbursement of a Disputed Amount, the ISO shall specify the amount to be reimbursed by such Affected Party and the calculations supporting the determination of such reimbursement amount. Subsequent to the provision of the written notice of the RBA Decision as set forth above, the ISO shall provide each Affected Party with respect to that RBA Decision a monthly report of the status of such RBA Decision within the dispute resolution process set forth in this Section 6, including a statement of the accounting treatment of the disputed amount owed by or to that Affected Party with respect to that RBA Decision in accordance with the most recent decision issued pursuant to Sections 6.3.6 or 6.4 of the ISO New England Billing Policy, whichever applies, with respect to that RBA Decision. For purposes of this Section, the term "Affected Parties" shall also include the Disputing Party.

Section 6.3.6 – Finality of ISO Action on Requested Billing Adjustment. Except as otherwise provided in this Section 6.3.6, the RBA Decision shall become final and binding on the Affected Parties and shall not be appealable in any forum on the twenty-first (21st) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above. The RBA Decision shall not become final or binding if, on or before the twentieth (20th) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above, an Affected Party has appealed the RBA Decision by commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction over the dispute, or has filed an appeal pursuant to Section 6.4 of the ISO New England Billing Policy. If a proceeding is commenced before the Commission or

other regulatory or judicial authority with jurisdiction over the dispute, the Affected Party commencing that proceeding shall simultaneously transmit a copy of its initial pleading in that proceeding to the ISO's designated representative for that particular RBA Decision, and to the Chair of the NEPOOL Budget and Finance Subcommittee and shall also submit to the ISO's designated representative for that particular RBA a copy of the final order or decision in that proceeding resolving the dispute. If any such appeal is filed pursuant to Section 6.4 of the ISO New England Billing Policy, the RBA Decision shall have no force or effect unless or until it is affirmed or upheld upon completion of the appeal process selected by the Affected Party and as provided for in the ISO New England Billing Policy.

Section 6.4 – Right of Affected Party to Review of ISO RBA Decision by AAA.

Section 6.4.1 – Right to Further Review. An Affected Party may seek review of an RBA Decision by an independent third party neutral by submitting, on or before the twentieth (20th) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above, a request for arbitration of the Requested Billing Adjustment with the American Arbitration Association ("AAA"). At the same time that it submits its request to the AAA, the Affected Party commencing any such review of an RBA Decision shall transmit its request for arbitration: (i) to the ISO's designated representative for that particular RBA Decision; and (ii) to each of the Affected Parties; and (iii) to the Chair of the NEPOOL Budget and Finance Subcommittee. The ISO and any Affected Party shall be joined as parties to the arbitration. NEPOOL and other Covered Entities shall be permitted to intervene in the arbitration if they desire to do so.

Section 6.4.2 – Finality of the AAA Neutral's Decision. Except as otherwise provided in this Section 6.4.2, the written, final decision of the AAA neutral shall become final and binding on the Affected Parties, including the ISO, and shall not be appealable in any forum on the twenty-first (21st) Business Day after the date on which the final decision of the AAA neutral was issued. The final decision of the AAA neutral shall not become final or binding if on or before the twentieth (20th) Business Day after the date on which the final decision of the AAA neutral was issued, an Affected Party or Parties or the ISO has appealed the final decision of the AAA neutral by commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction over the dispute. If any such appeal is filed, the final decision of the AAA

neutral shall have no force or effect unless or until it is affirmed or upheld upon completion of the appeal process.

Section 6.5 – Access to Confidential Information. Information that is deemed confidential pursuant to the ISO New England Information Policy in the possession, custody or control of the ISO concerning the dollar amount in Invoices or Remittance Advices issued by the ISO ("Confidential Information") shall be made available under these billing dispute procedures only to "Dispute Representatives" who have executed a confidentiality agreement in accordance both with this Section 6.5 and the ISO New England Information Policy in the form of Attachment 1 hereto ("Confidentiality Agreement"). A copy of the executed Confidentiality Agreement for a Dispute Representative shall be provided to the ISO prior to the disclosure of any Confidential Information to said Dispute Representative. Confidential Information shall not be disclosed to anyone other than in accordance with this Section 6.5, and shall be used only in connection with the billing dispute procedures provided under this Section 6.

a) *Potential Disputing Parties' Right of Access to Confidential Information.* A Market Participant, PTO or Non-Market Participant Transmission Customer that is a potential Disputing Party is entitled to obtain access to Confidential Information for its Dispute Representative, if and only if, it can demonstrate to the ISO that such access is required to determine if it has a substantive basis for filing a Requested Billing Adjustment with the ISO. Such demonstration by a potential Disputing Party, at a minimum, shall include: the information submitted to ISO Participant Support and Solutions required in Section 6.3.1; and, why lack of access to Confidential Information prevents the potential Disputing Party from determining if it has a substantive basis for filing such a Requested Billing Adjustment. A potential Disputing Party shall submit a request for access to Confidential Information in writing to the ISO (an "Information Request"). The ISO shall evaluate and respond to such an Information Request within ten (10) days of the receipt of the Information Request, and where the need for access to Confidential Information is demonstrated in accordance with the above, shall provide access to such Confidential Information within fifteen (15) days of the receipt of the Information Request.

b) *Affected Parties Right of Access to Confidential Information*. If the RBA Decision is submitted to the AAA for resolution pursuant to Section 6.4, then for purposes of that AAA proceeding a Market Participant or Non-Market Participant Transmission Customer that is an Affected Party is entitled to obtain access to Confidential Information for its Dispute Representative if, and only if, it can demonstrate to the AAA Neutral that such access is required to protect its financial interests with respect to review of an RBA Decision pending before the Neutral. An Affected Party shall submit a request for access to Confidential Information concerning an RBA Decision within the timeframes established by the Neutral. The Neutral shall have the authority to enter such orders as may be necessary to protect the Confidential Information, in accordance with applicable ISO policies including but not limited to the ISO New England Information Policy.

c) *Dispute Representatives.* Dispute Representatives shall be limited to the AAA Neutral(s), Covered Entities and third parties retained by and/or in-house legal counsel of the AAA or Covered Entities; provided, however, that Confidential Information may not be disclosed to a Dispute Representative to the extent the disclosure is prohibited by Order 889. A Dispute Representative may disclose Confidential Information to any other Dispute Representative as long as the disclosing Dispute Representative and the receiving Dispute Representative each have executed a Confidentiality Agreement. In the event that any Dispute Representative to whom Confidential Information is disclosed ceases to be engaged in a matter under these billing dispute procedures, or is no longer qualified to be a Dispute Representative under this Section, access to Confidential Information by that person, or persons, shall be terminated and all such Confidential Information received by that party shall be returned to the ISO or destroyed to the satisfaction of the ISO. Even if no longer engaged as a Dispute Representative under this Section, every person who has executed a Confidentiality Agreement shall continue to be bound by the provisions of this Section and such Confidentiality Agreement. All Dispute Representatives are responsible for ensuring that persons under their supervision or control comply with this Section and the Confidentiality Agreement.

d) *Maintenance of Confidential Information.* All copies of all documents and materials containing Confidential Information shall be maintained by Dispute Representatives at all times in a secure place in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Section. Such documents and material shall be marked PROTECTED CONFIDENTIAL INFORMATION and shall be maintained under seal and provided only to Dispute Representatives as are authorized to examine and inspect such Confidential Informational. Dispute Representatives shall provide to the ISO a list of those persons under the supervision and/or control of the Dispute Representative who are entitled to receive Confidential Information. Dispute Representatives shall take all reasonable precautions to ensure that Confidential Information is not distributed to unauthorized persons.

e) *ISO Right to Object to Access to Confidential Information*. Nothing in this Section shall be construed as precluding the ISO from objecting to providing any party access to Confidential Information on any legal grounds other than those provided under the ISO New England Information Policy, as it may be amended time to time.

SECTION 7 -WEEKLY BILLING PRINCIPLES FOR NON-HOURLY CHARGES.

The ISO shall administer weekly billing arrangements for Non-Hourly Charges and Transmission Charges that have been effected in special circumstances pursuant to the ISO New England Financial Assurance Policy according to the following principles:

Section 7.1 - Weekly Invoices. The ISO shall issue weekly Invoices for such Non-Hourly Charges and such Transmission Charges to any Market Participant or Non-Market Participant Transmission Customer for which such a weekly billing arrangement has been established to the extent such Market Participant's or Non-Market Participant Transmission Customer's Non-Hourly Charges and Transmission Charges exceed the Payments due to it for Non-Hourly Charges and Transmission Charges, respectively, for the current billing week. Such weekly Invoices for Non-Hourly Charges and for Transmission Charges would be issued and due at the same times as one of the twice weekly Invoices for Hourly Charges as determined by the ISO. Remittance Advices for Non-Hourly Charges and for Transmission Charges for such Market

Participants and Non-Market Participant Transmission Customers will still be issued monthly, in accordance with the procedures set forth above.

Section 7.2 -Basis for Billing. The amounts due from such Market Participant or Non-Market Participant Transmission Customer on weekly Invoices for Non-Hourly Charges and Transmission Charges shall be based on estimates derived by pro-rating the most recent final monthly Statements and Transmission Statements issued for such Market Participant or Non-Market Participant Transmission Customer.

Section 7.3 -Monthly Reconciliation. In connection with each monthly billing cycle, the ISO shall reconcile the sum of the weekly Invoices for Non-Hourly Charges and for Transmission Charges issued with the normal monthly billing quantities for such Non-Hourly Charges and Transmission Charges calculated for the Market Participant or Non-Market Participant Transmission Customer. The ISO shall perform a true-up of any amounts owed or due on the following weekly Statements or monthly Transmission Statements.

Section 7.4 – FTR-Only Customers. FTR-Only Customers are not eligible for weekly billing arrangements for Non-Hourly Charges.

Re: Requested Billing Adjustment _____

CONFIDENTIALITY AND NONDISCLOSURE AGREEMENT

The ISO ("Provider") agrees to make available, pursuant to Section 6 of the ISO New England Billing Policy, to _____ ("Recipient") confidential and proprietary information (Confidential Information") relevant to resolution of the Requested Billing Adjustment _____ and any appeals thereof as provided for in said Section 6.

1. Any information provided to the Recipient and labeled "Confidential Information" by Provider shall be confidential subject to this Agreement.
2. The Confidential Information is received by Recipient in confidence.
3. The Confidential Information shall not be used or disclosed by the Recipient except in accordance with the terms contained herein, with Section 5 of the ISO New England Billing Policy and with the ISO New England Information Policy.
4. Only individuals who are Dispute Representatives as that term is defined in Section 6 of the ISO New England Billing Policy, and not entities, may be Recipients of Confidential Information under this paragraph. By executing this Agreement, each Recipient certified that he/she meets the requirements of this Agreement.
5. The following conditions apply to each Recipient:
    a. Each Recipient will receive one (1) numbered, controlled copy of the Confidential Information. The Recipient will not make any copies thereof or provide the Confidential Information to any individual or entity except one who has executed and delivered an Agreement identical to this Agreement to the Provider.
    b. The Recipient shall maintain a log of all persons granted access to the Confidential Information.
    c. The Recipient, by signing this Agreement acknowledges that he/she may not in any manner disclose the Confidential Information to any person, and that he/she may not use the Confidential Information for the benefit of any person except in this proceeding and in accordance with the terms of this Agreement, Section 6 of the ISO New England Billing Policy and the ISO New England Information Policy.
    d. The Recipient acknowledges that any violation of this Agreement may subject the Recipient to civil actions for violation thereof.
    e. Within thirty (30) days of the final decision issued with respect to the Requested Billing Adjustment terminating all appeals with respect to this Requested Billing Adjustment, Recipient shall return the Confidential Information to Provider.

PROVIDER:	RECIPIENT:
By: _____	By:_____
Dated:_____	Dated:_____

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III.13.6.1.1.3 [Reserved.]

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III.13.6.1.6.1 Energy Market Offer Requirements.

III.13.6.1.7 Distributed Energy Capacity Resources with Capacity Supply Obligations.

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III.13.6.2.1.1.1 Day-Ahead Energy Market Participation.

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III.13.6.2.2.1 Energy Market Offer Requirements.

III.13.6.2.2.2 Day-Ahead Energy Market Participation.

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III.13.6.2.3.2 Additional Requirements for Intermittent Power Resources.

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III.13.6.2.5 Demand Capacity Resources without a Capacity Supply Obligation.

III.13.6.2.5.1. Energy Market Offer Requirements.

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III.14.5 Regulation Market Resource Selection.

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III.15.3.1.1 Resources Never Previously Counted as Capacity

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III.15.3.3 Qualified Capacity for Import Capacity Resources

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III.15.3.5.1 Summer and Winter Qualified Capacity

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III.15.5.1 Capacity Zones Included in Monthly Reconfiguration Auctions

III.15.5.2 Participation in Monthly Reconfiguration Auctions

III.15.5.2.1 Supply Offers in Monthly Reconfiguration Auctions

III.15.5.2.2 Demand Bids in Monthly Reconfiguration Auctions

III.15.5.3 Clearing Offers and Bids in Monthly Reconfiguration Auctions

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III.15.5.5 Adjustment to Capacity Supply Obligations

III.15.6 Bilateral Capacity Contracts

III.15.6.1 Capacity Supply Obligation Bilaterals.

III.15.6.1.1 Terms of and Participation in Capacity Supply Obligation Bilaterals

III.15.6.1.2 Timing of Submission and Prior Notification to the ISO

III.15.6.1.3 Contents of Submission to the ISO

III.15.6.1.4 ISO Review

III.15.6.1.5 Approval

III.15.6.2 Capacity Load Obligations Bilaterals

III.15.6.2.1 Terms of and Participation in Capacity Load Obligation Bilaterals

III.15.6.2.2 Timing of Submission to the ISO

III.15.6.2.3 Contents of Submission to the ISO

III.15.6.2.4 ISO Review

III.15.6.2.5 Approval

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III.15.7.1 Resources with Capacity Supply Obligations

III.15.7.1.1 Generating Capacity Resources with Capacity Supply Obligations

III.15.7.1.2 Import Capacity Resources with Capacity Supply Obligations

III.15.7.1.3 Intermittent Power Resources with Capacity Supply Obligations

III.15.7.1.4 [Reserved.]

III.15.7.1.5 Demand Capacity Resources with Capacity Supply Obligations

III.15.7.1.6 DNE Dispatchable Generator

III.15.7.1.7 Distributed Energy Capacity Resources with Capacity Supply Obligations

III.15.7.2 Resources without a Capacity Supply Obligation

III.15.7.2.1 Generating Capacity Resources without a Capacity Supply Obligation

III.15.7.2.2 Distributed Energy Capacity Resources without a Capacity Supply Obligation

III.15.7.2.3 Intermittent Power Resources without a Capacity Supply Obligation

III.15.7.2.4 [Reserved.]

III.15.7.2.5 Demand Capacity Resources without a Capacity Supply Obligation

III.15.7.3 Exporting Resources

III.15.7.4 ISO Requests for Energy

III.15.7.4.1 Real-Time High Operating Limit

III.15.8 Capacity Payments and Charges

III.15.8.1 Capacity Base Payments

III.15.8.1.1 Payments and Charges Reflecting Capacity Supply Obligations

III.15.8.1.2 Export Capacity

III.15.8.2 Capacity Performance Payments

III.15.8.2.1 Definition of Capacity Scarcity Condition

III.15.8.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition

III.15.8.2.3 Capacity Balancing Ratio

III.15.8.2.4 Capacity Performance Score

III.15.8.2.5 Capacity Performance Payment Rate

III.15.8.2.6 Calculation of Capacity Performance Payments

III.15.8.2.A System-Backed Export Charges.

III.15.8.2.A.1 System-Backed Exports.

III.15.8.2.A.2 Calculation of System-Backed Export Charges.

III.15.8.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism

III.15.8.3.1 Monthly Stop-Loss

III.15.8.3.2 Annual Stop-Loss

III.15.8.4 Allocation of Deficient or Excess Capacity Performance Payments and System-Backed Export Charges

III.15.8.5 Charges to Market Participants with Capacity Load Obligations

III.15.8.5.1 Calculation of Capacity Charges

III.15.8.5.2 Calculation of Capacity Load Obligation and Zonal Capacity Obligation

III.15.8.5.3 Excess Revenues

III.15.8.5.4 Capacity Transfer Rights

III.15.8.5.4.1 Specifically Allocated CTRs Associated with Transmission Upgrades

III.15.8.5.4.2 Specifically Allocated CTRs for Pool-Planned Units

III.15.8.5.5 Annual Capacity Market Net Charge Amount

III.15.9 Information Publication and Reporting

III.13.7. Performance, Payments and Charges in the FCM.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1.

III.13.7.1.1. Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.13.7.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(a) **Forward Capacity Auction**. For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated

with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

(d) **Substitution Auctions.** For a resource whose offer or bid has cleared in a substitution auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the substitution auction clearing price. Notwithstanding the foregoing, the monthly capacity charge for a demand bid cleared at a substitution auction clearing price above its bid price shall be calculated using its bid price.

III.13.7.1.3. Export Capacity.

If there are any Export Bids or Administrative Export De-List Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows.

Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-List Bid]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located= [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.5.2.

III.13.7.1.4. [Reserved.]

III.13.7.2 Capacity Performance Payments.

III.13.7.2.1 Definition of Capacity Scarcity Condition.

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.13.7.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition

shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource or Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures, the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.13.7.2.2(c), for any On-Peak Demand Resource or Seasonal Peak Demand Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.13.7.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(i) A Demand Response Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource

was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource's Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource's Actual Capacity Provided shall not be less than zero.

(ii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

(e) A Distributed Energy Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Metered Quantity for Settlement and Reserve Quantity for Settlement of all the components of its constituent Distributed Energy Resource Aggregations; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Based on the Real-Time operational coordination, the resource must follow any distribution system limitation and update its physical parameters accordingly. The Actual Capacity Provided cannot be less than zero.

(i) The Real-Time demand reduction of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled

curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource or Demand Response Distributed Energy Resource Aggregation does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

provided, however, that the Capacity Balancing Ratio shall not exceed a value of 1.0.

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.13.7.2.A.2 in the New England Control Area during the interval.

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.13.7.2.A.2 in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.13.7.2.A.2 in the Capacity Zone during the interval.

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

III.13.7.2.4 Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero)

and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a Seasonal Peak Demand Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025, the Capacity Performance Payment Rate shall be $5455/MWh. For the period beginning on June 1, 2025 and ending on August 31, 2026, the Capacity Performance Payment Rate shall be $9337/MWh. Thereafter, the Capacity Performance Payment Rate shall be $3500/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.13.7.2.6 Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.13.7.2.A System-Backed Export Charges.

III.13.7.2.A.1 System-Backed Exports.

A System-Backed Export is an External Transaction submitted in accordance with Section III.1.10.7 or Section III.1.10.7.A to export internal energy out of the New England Control Area by a Market Participant in the Real-Time Energy Market: (1) that is not associated with a generator; or (2) for External Transactions associated with a generator, for which the megawatt amount of the External Transaction sale(s) associated with the generator is greater than the sum of the resource's energy output plus the resource's Reserve Quantity For Settlement.

III.13.7.2.A.2 Calculation of System-Backed Export Charges.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a System-Backed Export Charge: (1) for External Transactions associated with a generator, for each resource that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval; and (2) for External Transactions not associated with a generator, for each Market Participant that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval. For each five-minute interval, the System-Backed Export Charge shall be equal to the net System-Backed Export value, calculated in accordance with the formulas set forth below, multiplied by the Capacity Performance Payment Rate, as defined in Section III.13.7.2.5.

For External Transactions associated with a generator,

net System-Backed Export value = the lesser of (the energy output of the generator in the interval + the Reserve Quantity for Settlement of the generator in the interval – the hourly integrated delivered MW for the External Transaction sale(s) associated with the generator) or 0

System-Backed Export Charge = net System-Backed Export value × Capacity Performance Payment Rate

For External Transactions not associated with a generator,

net System-Backed Export value = the lesser of (the hourly integrated delivered MW for the External Transaction purchase(s) of the Market Participant – the hourly integrated delivered MW for the External Transaction sale(s) of the Market Participant) or 0

System-Backed Export Charge = net System-Backed Export value × Capacity Performance Payment Rate

Unless otherwise expressly stated, a System-Backed Export Charge shall not be treated as a Capacity Performance Payment under the Tariff.

III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below.

III.13.7.3.1 Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month (or, in the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource's Capacity Supply Obligation for the Obligation Month).

III.13.7.3.2 Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [3 months x (FCAcp – FCAsp) – (12 months x FCAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCAcp = the Capacity Clearing Price for the relevant Forward Capacity Auction.

FCAsp = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.13.7.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply

Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.13.7.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.13.7.3.2(b).

III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments and System-Backed Export Charges.

For Capacity Scarcity Conditions, as described in Section III.13.7.2.1, the ISO shall allocate deficient or excess Capacity Performance Payments and System-Backed Export Charges as described in subsections (a), (b), and (c) below.

(a) If the sum of all Capacity Performance Payments and System-Backed Export Charges to all resources subject to a Capacity Scarcity Condition in an Obligation Month is positive, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the deficiency shall be charged to resources in proportion to the sum of each such resource's positive Capacity Performance Score for the Obligation Month.

(b) If the sum of all Capacity Performance Payments and System-Backed Export Charges to all resources subject to a Capacity Scarcity Condition in an Obligation Month is negative, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the excess shall be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess shall be further allocated to other resources in the same manner as described in this Section III.13.7.4(b).

(c) If a deficiency of Capacity Performance Payments exists due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the deficiency shall be charged to all resources subject to a Capacity Scarcity Condition in an Obligation Month that have not reached their stop-loss limit (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. If the charge described in Section

III.13.7.4(a) or the charge described in this Section III.13.7.4(c) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss limit described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(c).

III.13.7.5. Charges to Market Participants with Capacity Load Obligations.

III.13.7.5.1. Calculation of Capacity Charges Prior to June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning prior to June 1, 2022. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month may also receive a failure to cover credit equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone, and; (b) the sum of all failure to cover charges in the Capacity Zone calculated pursuant to Section III.13.3.4(b), divided by total Capacity Load Obligation in the Capacity Zone.

III.13.7.5.1.1. Calculation of Capacity Charges On and After June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning on or after June 1, 2022. For purposes of this Section III.13.7.5.1.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in subsection (b) of Sections III.13.7.5.1.1.1 through III.13.7.5.1.1.9 will be divided by the number of days in the month to derive a daily settlement value.

III.13.7.5.1.1.1 Forward Capacity Auction Charge.

The FCA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone FCA Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone FCA Costs, for each Capacity Zone, are the Total FCA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total FCA Costs are the sum of, for all Capacity Zones, (i) Capacity Supply Obligations in each zone (the total obligation awarded to or shed by resources in the Forward Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.13.7.5.1.1.6 and excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) multiplied by the applicable clearing price from the auction in which the obligation was awarded to (or shed by) the resource, and (ii) the difference between the bid price and the substitution auction clearing price that was not included in the capacity charge pursuant to the second sentence of Section III.13.7.1.1(d). Capacity Supply Obligations awarded to Proxy De-List Bids in the primary auction, or shed by demand bids entered into the substitution auction on behalf of a Proxy De-List Bid, are excluded from Total FCA Costs.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.1.1.2 Annual Reconfiguration Auction Charge.

The total annual reconfiguration auction charge, for each Capacity Zone and each associated annual reconfiguration auction, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone Annual Reconfiguration Auction Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone Annual Reconfiguration Auction Costs, for each Capacity Zone, are the Total Annual Reconfiguration Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total Annual Reconfiguration Auction Costs are the sum, for all Capacity Zones and each associated annual reconfiguration auction, of the product of the Capacity Supply Obligations acquired through the annual reconfiguration auction in each zone (adjusted for any obligations procured in the annual reconfiguration auction that are subsequently terminated pursuant to Section III.13.3.4A) and the zonal annual reconfiguration auction clearing price, minus the sum, for all Capacity Zones, of the product of the amount of any Capacity Supply Obligation shed through the annual reconfiguration auction in each zone and the applicable annual reconfiguration auction clearing price.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.1.1.3. Monthly Reconfiguration Auction Charge.

The monthly reconfiguration auction charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total Monthly Reconfiguration Auction Costs divided by Total Zonal Capacity Obligation.

Where

Total Monthly Reconfiguration Auction Costs are the sum of, for all Capacity Zones, the product of Capacity Supply Obligations acquired through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price, minus the sum of, for all Capacity Zones, any Capacity Supply Obligations shed through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price.

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.4. HQICC Capacity Charge.

The HQICC capacity charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total HQICC Credits divided by Total Capacity Load Obligation.

Where

Total HQICC credits are the product of HQICCs multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone in which the HQ Phase I/II external node is located.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.5. Self-Supply Adjustment.

The self-supply adjustment is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) the Self-Supply Variance divided by Total Capacity Load Obligation.

Where

Self-Supply Variance is the difference between foregone capacity payments and avoided capacity charges associated with designated self-supply quantities.

Foregone capacity payments to Self-Supplied FCA Resources are the sum, for all Capacity Zones, of the product of the zonal Capacity Supply Obligation (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) designated as self-supply, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Avoided capacity charges are the sum, for all Capacity Zones, of the product of any designated self-supply quantities multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone associated with the designated self-supply quantity.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.6. Intermittent Power Resource Capacity Adjustment.

The Intermittent Power Resource capacity adjustment in a winter season for the Obligation Months from October through May is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) the Intermittent Power Resource Seasonal Variance divided by Total Zonal Capacity Obligation.

Where

Intermittent Power Resource Seasonal Variance is the difference between the FCA payments for Intermittent Power Resource in the Obligation Month and the base FCA payments for Intermittent Power Resources.

FCA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to or shed by Intermittent Power Resources in the Forward Capacity Auction process for the Obligation Month pursuant to Section III.13.2.7.6 or Section III.13.2.8.1.1 (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Base FCA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the FCA Qualified Capacity procured from or shed by Intermittent Power Resources in the Forward Capacity Auction process (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Total Zonal Capacity Obligation is the total Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.7. Multi-Year Rate Election Adjustment.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

Zonal Multi-Year Rate Election Costs is the sum, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public

Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, multiplied by the Zonal Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation and divided by the Total Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning prior to June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

Zonal Multi-Year Rate Election Costs is the sum in each Capacity Zone, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period.

III.13.7.5.1.1.8 CTR Transmission Upgrade Charge.

The CTR transmission upgrade charge is: (a) the Capacity Load Obligation in the Capacity Zones to which the applicable interface limits the transfer of capacity, multiplied by (b) Zonal CTR Transmission Upgrade Cost divided by Zonal Capacity Obligation.

Where

Zonal CTR Transmission Upgrade Cost for each Capacity Zone to which the interface limits the transfer of capacity is the amount calculated pursuant to Section III.13.7.5.4.4 (f), multiplied by the Zonal Capacity Obligation and divided by the sum of the Zonal Capacity Obligation for all Capacity Zones to which the interface limits the transfer of capacity.

III.13.7.5.1.1.9 CTR Pool-Planned Unit Charge.

The CTR Pool-Planned Unit charge is: (a) the total Capacity Load Obligation in all Capacity Zones less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5, multiplied by (b) CTR Pool-Planned Unit Cost divided by Total Zonal Capacity Obligation less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5.

Where

The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.13.7.5.4.5 (b).

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.10. Failure to Cover Charge Adjustment.

The failure to cover charge adjustment, for each Capacity Zone, is (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Failure to Cover Charges divided by Total Capacity Load Obligation.

Where:

Zonal Failure to Cover Charges are the product of: (1) the sum, for all Capacity Zones, of the failure to cover charges calculated pursuant to Section III.13.3.4(b), and; (2) the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price as determined pursuant to Section III.13.3.4.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.2. Calculation of Capacity Load Obligation and Zonal Capacity Obligation.
The ISO shall assign each Market Participant a share of the Zonal Capacity Obligation prior to the commencement of each Obligation Month for each Capacity Zone established in the Forward Capacity Auction pursuant to Section III.13.2.3.4. The Zonal Capacity Obligation of a Capacity Zone that contains a nested Capacity Zone shall exclude the Zonal Capacity Obligation of the nested Capacity Zone.

Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals for Capacity Commitment Periods beginning prior to June 1, 2022 and excluding any additional obligations awarded to Intermittent Power Resources pursuant to Section III.13.2.7.6 that exceed the FCA Qualified Capacity procured in the Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022) plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022) to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022).

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with the receipt of electricity from the grid by Storage DARDs for later injection of electricity back to the grid; when all load of a Distributed Energy Resource Aggregation participating as a Storage DARD is load associated with the receipt of electricity from the grid for later injection of electricity back to the grid; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as a discrete Load Asset and is exclusively related to an Alternative Technology Regulation Resource following AGC Dispatch Instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A Market Participant's share of Zonal Capacity Obligation for each day of the month and each Capacity Zone shall equal the product of: (i) the Capacity Zone's Zonal Capacity Obligation as calculated above and (ii) the ratio of the sum of the load serving entity's daily Coincident Peak Contributions, to the sum of all load serving entities' daily Coincident Peak Contributions in that Capacity Zone.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each day of the month and each Capacity Zone, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations. A Capacity Load Obligation can be a positive or negative value.

A Market Participant's share of Zonal Capacity Obligation will not be reconstituted to include the demand reduction of a Demand Capacity Resource, Demand Response Resource, or a Demand Response Distributed Energy Resource Aggregation.

III.13.7.5.2.1. Charges Associated with Dispatchable Asset Related Demands.

Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.5.3. Excess Revenues.

(a) For Capacity Commitment Periods beginning prior to June 1, 2022, revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.5.3.

(b) Any payment associated with a Capacity Supply Obligation Bilateral that was to accrue to a Capacity Acquiring Resource for a Capacity Supply Obligation that is terminated pursuant to Section

III.13.3.4A shall instead be allocated to Market Participants based on their pro rata share of all Capacity Load Obligations in the Capacity Zone in which the terminated resource is located.

III.13.7.5.4. Capacity Transfer Rights.

III.13.7.5.4.1. Definition and Payments to Holders of Capacity Transfer Rights.
This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

Capacity Transfer Rights are calculated for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone's Net Regional Clearing Price and absolute value of each Capacity Zone's Capacity Load Obligations, as calculated in Section III.13.7.5.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total

Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources.

III.13.7.5.4.2. Allocation of Capacity Transfer Rights.

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.5.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Connecticut Import Interface**. The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) **NEMA/Boston Import Interface**. Except as provided in Section III.13.7.5.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

III.13.7.5.4.3. Allocations of CTRs Resulting From Revised Capacity Zones.

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.5.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.5.4.4. Specifically Allocated CTRs Associated with Transmission Upgrades.

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(e) **Maine Export Interface**. Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine export interface for as long as Casco Bay continues to pay to support the transmission upgrades.

(f) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. This value will be divided by the number of days in the month to derive a daily settlement value.

III.13.7.5.4.5. Specifically Allocated CTRs for Pool-Planned Units.

(a) In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive for each Capacity Commitment Period an allocation of CTRs for each such unit that is the product of: (i) the MW quantity of capacity that the unit cleared in the Forward Capacity Auction associated with the Capacity Commitment Period; and (ii) the municipal utility's ownership entitlements in such unit. The CTRs allocated pursuant to this Section may be designated as self-supply quantities as described in Section III.13.1.6. Municipal utility ownership entitlements are set as shown in the table below and are not transferrable.

	Millstone 3	Seabrook	Stonybrook GT 1A	Stonybrook GT 1B	Stonybrook GT 1C	Stonybrook 2A	Stonybrook 2B	Wyman 4		
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%		
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%		
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%		
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%		
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%		
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%		
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%		
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%		
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%		
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%		
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%		
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%		
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%		
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%		
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%		
Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%		
Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%		
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%		
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%		

Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%		
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%		
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%		
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%		
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%		
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%		
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%		
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%		
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%		
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%		
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%		
Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%		

Allocation of CTRs as described in this Section shall expire on December 31, 2040. If a unit listed in the table above retires prior to December 31, 2040, however, allocation of CTRs for such unit shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant ("WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

(b) For any CTRs specifically allocated pursuant to this Section that are not designated self-supply quantities for the Capacity Commitment Period, the municipal utility entitlement holder shall receive a credit reflecting the value of such remaining CTRs. The value of each remaining CTR shall be calculated as the product of: (i) the Capacity Clearing Price for the Capacity Zone where the load of the municipal utility entitlement holder is located minus the Capacity Clearing Price for the Capacity Zone in which the Pool-Planned Unit is located; and (ii) the remaining MW quantity. This value will be divided by the number of days in the month to derive a daily settlement value.

III.13.7.5.5. Forward Capacity Market Net Charge Amount.

The Forward Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charges; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund (for Capacity Commitment Periods beginning prior to June 1, 2022); and (d) any applicable export charges.

III.15. Annual Capacity Market.

(a) Annual Capacity Market Overview.

The ISO shall administer an annual market for capacity (Annual Capacity Market) in accordance with the provisions of this Section III.15. For each one-year period from June 1 through May 31, starting with the period June 1, 2028 to May 31, 2029, for which Capacity Supply Obligations are assumed and payments are made in the Annual Capacity Market ("Capacity Commitment Period"), the ISO shall conduct an Annual Capacity Auction in accordance with the provisions of Section III.15.4 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Annual Capacity Auction, a resource must have Qualified Capacity resulting from the Annual Capacity Auction qualification process in accordance with the provisions of Sections III.15.2 and III.15.3. Obligations associated with the Annual Capacity Market may be traded during ISO-administered Monthly Reconfiguration Auctions and monthly bilateral transactions, in accordance with Section III.15.5 and Section III.15.6, respectively. The obligations of resources with Capacity Supply Obligations resulting from the Annual Capacity Auction, Monthly Reconfiguration Auctions, and monthly bilateral transactions are set forth in Section III.15.7. Payments and charges resulting from participation in the Annual Capacity Market, Monthly Reconfiguration Auctions, and bilateral transactions, as well as Capacity Performance Payments and System-Backed Export Charges, are set forth in Section III.15.8. The publication of auction-related information is set forth in Section III.15.9.

(b) Capacity Auction Calendar.

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2028, and for each Capacity Commitment Period thereafter, the ISO shall publish a calendar of dates and deadlines for the administration of the Capacity Market, with the dates and deadlines being consistent for each Annual Capacity Auction cycle. The Capacity Auction Calendar shall include specific dates and deadlines for all such Capacity Market dates and deadlines defined in this Section III.15 and related Tariff provisions. The following defines several milestone dates and deadlines.

(1) the Qualification Data Submission Deadline for the Annual Capacity Auction shall occur during the month of February;

(2) the Capacity Demonstration Deadline for the Annual Capacity Auction shall occur during the month of April; and

(3) the Annual Capacity Auction shall occur during the month of May.

(c) Modification of Capacity Auction Calendar.

The ISO may, on a prospective basis, reasonably revise any date or deadline in the Capacity Auction Calendar with written notice of such revision to each Governance Participant in the manner specified in Section 17.11(b) of the Participants Agreement prior to the occurrence of the date or deadline being revised. In the event a Market Participant fails to meet a deadline in the Capacity Auction Calendar for submission of information or data, the ISO shall extend such deadline for that Market Participant upon receipt of an order from the Commission granting the Market Participant's request for a waiver of such deadline for good cause shown. In no event shall a date or deadline be extended, prospectively by the ISO or retroactively by filing of a Market Participant, should doing so interfere with the ISO's effective administration of the Capacity Market.

(d) Effectiveness for the 2028-2029 Capacity Commitment Period and Thereafter.

The provisions of this Section III.15 are effective for the Capacity Commitment Period that runs from June 1, 2028 through May 31, 2029 and all Capacity Commitment Periods thereafter. Unless otherwise expressly stated, the provisions of this Section III.15 are not applicable to the Forward Capacity Market. Section III.13, addressing the administration of the Forward Capacity Market, shall continue to be effective for Capacity Commitment Periods through May 31, 2028. Unless otherwise expressly stated, the provisions of Section III.13 are not applicable to the Annual Capacity Market, Monthly Reconfiguration Auctions and monthly bilateral transactions addressed in this Section III.15 of Market Rule 1.

III.15.A. Non-Commercial Capacity Transition Rules.

All Capacity Resources that are on critical path schedule monitoring pursuant to Section III.13.3 as of June 1, 2028 are subject to the provisions of this Section III.15.A.

The ISO shall monitor the Non-Commercial Capacity resource's compliance with its critical path schedule from the time the ISO approves the request until the resource achieves FCM Commercial Operation, is terminated pursuant to Section III.15.A.2.1, or withdraws from critical path schedule monitoring pursuant to Section III.15.A.2.3.

III.15.A.1. Non-Commercial Capacity Resource Critical Path Schedule Reports.

For each resource that is being monitored for compliance with its critical path schedule, the Lead Market Participant for that resource must provide a written critical path schedule report to the ISO no later than five Business Days after the end of each calendar quarter. If the Lead Market Participant does not provide a written critical path schedule report to the ISO by the fifth Business Day after the end of the calendar quarter, then the ISO shall issue a notice thereof to the Lead Market Participant. If the Lead Market Participant fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.15.A.2.1. Each critical path schedule report shall include a complete updated version of the critical path schedule as described in Section III.15.A.1.1 through Section III.15.A.1.3.

III.15.A.1.1. Updated Critical Path Schedule.

The critical path schedule report must include a complete updated version of the critical path schedule as described in Section III.15.A.1, dated contemporaneously with the submission of the critical path schedule report. The updated critical path schedule must clearly indicate if the Lead Market Participant is proposing to change any of the milestones or dates from the previously submitted version of the critical path schedule, and must include an explanation of any such proposed changes. In the critical path schedule report, the Lead Market Participant must also explain in detail any proposed changes to the project design and the potential impact of such changes on the amount of capacity the resource will be able to provide.

III.15.A.1.2. Documentation of Milestones Achieved.

(a) For all new resources (except for Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW,

which are discussed in Section III.15.A.1.2(b)), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Lead Market Participant must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Major Permits**. For each major permit described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the permit was applied for and obtained as described in the critical path schedule. For permit applications, this documentation could include a dated copy of the permit application or cover letter requesting the permit. For approved permits, this documentation could include a dated copy of the approved permit or letter granting the permit from the permitting authority.

(ii) **Project Financing Closing**. The Lead Market Participant shall provide documentation showing that the sources of financing identified in the critical path schedule have committed to provide the amount of financing described in the critical path schedule. This documentation could include copies of commitment letters from the sources of financing.

(iii) **Major Equipment Orders**. For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the equipment was ordered as described in the critical path schedule. This documentation should include a copy of a dated confirmation of the order from the manufacturer or supplier. This documentation should confirm scheduled delivery dates consistent with milestone Section III.15.A.1.2(a)(v).

(iv) **Substantial Site Construction.** The Lead Market Participant shall provide documentation showing that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs.

(v) **Major Equipment Delivery**. For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the equipment was delivered to the project site and received as preliminarily acceptable as described in the critical path schedule. This documentation should include a copy of a dated confirmation of delivery to the project site.

(vi) **Major Equipment Testing.** For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the component was tested, including major systems testing as appropriate for the specific technology as described in the critical path schedule, and that the test results demonstrate the equipment's suitability to allow, in conjunction with other major components, subsequent operation of the project in accordance with the amount of capacity subject to critical path schedule monitoring in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning**. The Lead Market Participant shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity subject to critical path schedule monitoring. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Lead Market Participant is not required to provide documentation of Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) to the ISO as part of the ISO's critical path schedule monitoring. The ISO shall confirm that the resource has achieved Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) as described in the critical path schedule through the resource's compliance with the other relevant requirements of the Transmission, Markets and Services Tariff and the ISO New England System Rules.

(ix) **Transmission Upgrades**. The Lead Market Participant shall provide documentation showing that all interconnection facilities and upgrades identified for the project associated with the resource in a Transitional Cluster Study, Cluster Study, or Cluster Restudy (conducted pursuant to Section 7.5 of Schedule 22, Section 7.5 of Schedule 23, or Section 7.5 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff), or interconnection request or agreement under applicable state tariff, rules or procedures, have been completed.

(b) For Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Lead Market

Participant must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Substantial Project Completion**. The Lead Market Participant shall provide documentation showing the resource will be capable of providing its total offered demand reduction value as described in the New Demand Capacity Resource Qualification Package by the proposed Commercial Operation Date reported in the critical path schedule report.

(ii) **Additional Requirements**. For each customer and each prospective customer the Lead Market Participant shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's Asset has been registered with the ISO, then the Lead Market Participant shall also provide the Asset identification number.

III.15.A.1.3. Additional Relevant Information.

The Lead Market Participant must include in the critical path schedule report any other information regarding the status or progress of the project or any of the project milestones that might be relevant to the ISO's evaluation of the feasibility of the project being built in accordance with the critical path schedule.

III.15.A.2. Failure to Meet Critical Path Schedule.

If the ISO determines that any critical path schedule milestone date has been missed, or if the Lead Market Participant proposes a change to any milestone date in a quarterly critical path schedule report (as described in Section III.15.A.1), then the ISO shall consult with the Lead Market Participant to determine the impact of the missed milestone or proposed revision, and shall determine a revised date for the milestone and for any other milestones affected by the change. If a milestone date is revised for any reason, the ISO may require the Lead Market Participant to submit a written report to the ISO on the fifth Business Day of each month until the revised milestone is achieved detailing the progress toward meeting the revised milestone. If the Lead Market Participant does not provide a written critical path schedule report to the ISO on the fifth Business Day of a month, then the ISO shall issue a notice thereof to the Lead Market Participant. If the Lead Market Participant fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.15.A.2.1. Such a monthly reporting requirement, if imposed, shall be in addition to the quarterly critical path schedule reports described in Section III.15.A.1.

III.15.A.2.1. Termination of Critical Path Schedule Monitoring.

If a Lead Market Participant fails to comply with the requirements of Sections III.15.A.1 or III.15.A.2, or if, as a result of milestone date revisions, the date by which a resource will have achieved all its critical path schedule milestones is more than two years after the beginning of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation, then the ISO, after consultation with the Lead Market Participant, shall have the right, through a filing with the Commission, to terminate the resource's status on critical path schedule monitoring, provided that, where a Lead Market Participant voluntarily withdraws its resource from critical path schedule monitoring in accordance with Section III.15.A.2.3 no filing with the Commission shall be necessary. Upon Commission ruling, the Lead Market Participant shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation. If in these circumstances, however, the ISO does not take steps to terminate the resource and instead permits the Lead Market Participant to continue on critical path schedule monitoring, such continuation shall be subject to the ISO's right to revoke that permission and to file with the Commission to terminate the resource, and subject to continued reporting by the Lead Market Participant in accordance with Section III.15.A.1.

III.15.A.2.2. Termination of Interconnection Agreement.

If the ISO terminates, or files with the Commission to terminate, a resource's ability to remain on critical path schedule monitoring, the ISO shall have the right to terminate the Interconnection Agreement with that resource through a filing with the Commission and upon Commission ruling. The ISO shall also reduce the resource's assigned capacity interconnection service (or equivalent for resources not subject to the ISO Interconnection Procedures).

III.15.A.2.3. Withdrawal from Critical Path Schedule Monitoring.

A Lead Market Participant may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO.

III.15.A.3. Financial Assurance.

The financial assurance requirements for Designated FCM Participants offering Non-Commercial Capacity into the Forward Capacity Auction, as described in Section VII.B.2.b the ISO New England Financial Assurance Policy, shall continue to apply to all Capacity Resources that are subject to the provisions of this Section III.15.A.

Once a resource with Non-Commercial Capacity achieves commercial operation, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as a resource that has achieved Capacity Market Commercial Operation, as governed by the ISO New England Financial Assurance Policy.

If a Capacity Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited. Any financial assurance that is forfeited pursuant to Section III.15.A shall be used to reduce charges incurred by load in the relevant Capacity Zone.

III.15.A.4. Demonstrating FCM Commercial Operation

All Capacity Resources subject to the provisions of this Section III.15.A shall achieve commercial operation, for purposes of ending critical path schedule monitoring, in accordance with the FCM Commercial Operation requirements specified in Section III.13.3.8.

III.15.A.5. Settlement of Qualification Process Cost Reimbursement Deposit.

Upon the date on which the entire resource is no longer on critical path schedule monitoring, the ISO shall provide the Lead Market Participant with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff. All Capacity Resources that are subject to the provisions of this Section III.15.A shall be subject to the Forward Capacity Market payment and refund requirements as set forth in Section III.13.1.9.3.2 of the Tariff.

III.15.1. Auction Demand Curves and Other Auction Inputs.

III.15.1.1. Annual Capacity Auction Demand Curves.

The total amount of capacity cleared in the Annual Capacity Auction pursuant to Section III.15.4 shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the Capacity Zones modeled for the Annual Capacity Auction.

III.15.1.1.1. System-Wide Capacity Demand Curve.

The System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.15.1.1.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Capacity Auction Offer Price Cap.

III.15.1.1.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.15.1.1.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Capacity Auction Offer Price Cap.

III.15.1.1.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.15.1.1.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.15.1.1.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.15.1.2. Capacity Auction Offer Price Cap and the Cost of New Entry.

III.15.1.2.1. Calculation of Capacity Auction Offer Price Cap, CONE, and Net CONE.

(a) The Capacity Auction Offer Price Cap shall be the greater of (i) 1.6 multiplied by Net CONE; and (ii) CONE. References in this Section III.15 and Sections III.A.21 and III.A.24 to the Capacity Auction Offer Price Cap shall mean the Capacity Auction Offer Price Cap for the Annual Capacity Auction associated with the relevant Capacity Commitment Period.

(b) To determine the CONE and Net CONE for the Annual Capacity Auctions associated with the Capacity Commitment Period beginning on June 1, 2028 and the Capacity Commitment Period beginning on June 1, 2029, the ISO shall make interim-year adjustments as described in Section III.15.1.2.2 to the following CONE and Net CONE calculated for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025:

(i) CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 was $12.400/kW-month.

(ii) Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 was $7.468/kW-month.

(c) The ISO shall recalculate CONE and Net CONE for the Annual Capacity Auction for the Capacity Commitment Period beginning on June 1, 2030. Thereafter, CONE and Net CONE shall be recalculated no less often than once every four years. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders, and the new values will be filed with the Commission prior to the Annual Capacity Auction in which the new value is to apply.

III.15.1.2.2. Interim-Year Adjustments to CONE and Net CONE.

(a) For years in which no full recalculation is performed pursuant to Section III.15.1.2.1, CONE and Net CONE shall be adjusted for each Annual Capacity Auction with the following updates to the capital

budgeting model used to calculate the CONE and Net CONE values set forth above in this Section III.15.1.2:

(1) Each line item associated with capital costs that is included in the capital budgeting model shall be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114).

(2) For each line item in (1) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the CONE and Net CONE values set forth in Section III.15.1.2.1. The value of each line item associated with capital costs in the capital budgeting model will be adjusted by the relevant multiplier.

(3) The energy and ancillary services offset values in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE, for each month of the Capacity Commitment Period to which the updated value will apply.

(4) The annual adjustment to CONE and Net CONE for the Annual Capacity Auction for the Capacity Commitment Period beginning June 1, 2028, shall use a cost of debt of 6.85% and a cost of equity of 13.80%. These values shall also be used for the Annual Capacity Auction for the Capacity Commitment Period beginning on June 1, 2029.

(5) If any of the values required for the calculations described in this Section III.15.1.2.2 are unavailable, then comparable values, prices or sources shall be used.

(b) The CONE and Net CONE values adjusted pursuant to this Section III.15.1.2.2 will be published on the ISO's website.

III.15.2. Capacity Resource Qualification.

Each resource, or portion thereof, must qualify as a Generating Capacity Resource, an Import Capacity Resource, a Demand Capacity Resource, or a Distributed Energy Capacity Resource. Each resource must be at least 100 kW in size to participate in an Annual Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of Section III.13 became effective. The summer period of a Capacity Resource's Seasonal Qualified Capacity Values shall be the months of June through September and the winter period shall be the months of October through May, except in the case of Demand Capacity Resources, where the summer period shall be the months of April through November and the winter period shall be the months of December through March.

This Section III.15.2 details the requirements of the qualification process for the Annual Capacity Auction, as well as certain requirements related to Monthly Reconfiguration Auctions and Capacity Supply Obligation Bilateral transactions. Data submission and demonstration requirements for resources that have never previously counted as capacity and seek to qualify to participate in an Annual Capacity Auction, are set forth in Section III.15.2.1. Data submission and demonstration requirements for resources that have never previously counted as capacity and seek to qualify to participate in a Monthly Reconfiguration Auction are set forth in Section III.15.2.2. Qualification requirements with respect to interconnection service are addressed in Section III.15.2.3. Qualification requirements with respect to resources that have previously counted as capacity and have materially changed are addressed in Section III.15.2.4. Following the Annual Capacity Auction's Qualification Data Submission Deadline, the ISO calculates and provides to Lead Market Participants Advisory Qualified Capacity Values for each Capacity Resource, per Section III.15.2.5. Lead Market Participants then have until the Capacity Demonstration Deadline to demonstrate that their Capacity Resources have achieved Commercial Operation, per Section III.15.2.6. Thereafter, the ISO calculates Seasonal Qualified Capacity Values for each Capacity Resource, per Section III.15.2.7, which values are subject to the challenge process addressed therein. Lead Market Participants are then permitted to submit Composite Offers in accordance with Section III.15.2.8, and load serving entities are permitted to submit self-supply designations in accordance with III.15.2.9. Final Qualified Capacity values for each Capacity Resource are calculated by the ISO one Business Day prior to the opening of the Annual Capacity Auction Offer Window in accordance with Section III.15.2.10. The publication of offer information during the qualification process and after the Annual Capacity Auction is addressed in Section III.15.2.11.

Resources seeking to qualify for an Annual Capacity Auction may be subject to buyer-side market power review and mitigation pursuant to Section III.A.21 and must abide by the applicable submission

requirements and timelines set forth therein prior to seeking to qualify for an Annual Capacity Auction. To the extent not already established for the purposes of the submission requirements of Section III.A.21.1.5, all capacity suppliers seeking to qualify for an Annual Capacity Auction must be Market Participants prior to the Qualification Data Submission Deadline. The Lead Market Participant for a resource participating in an Annual Capacity Auction may not change during the period beginning 15 Business Days prior to the opening of the Annual Capacity Auction Offer Window and ending with the posting of the results of the Annual Capacity Auction.

III.15.2.1. Qualification Data Submission Requirements.

III.15.2.1.1. Qualification Data Submission Package.

(a) For a resource that has not previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction to qualify as a Capacity Resource for participation in an Annual Capacity Auction, a Lead Market Participant must submit the following information to the ISO by the Qualification Data Submission Deadline, as applicable:

(i) the resource name;

(ii) the Lead Market Participant's contact information;

(iii) the date by which the resource is expected to complete its capacity demonstration pursuant to III.15.2.6(c) or to update its as-built data pursuant to III.15.2.6(d);

(iv) the resource address or location, and if available, asset identification number;

(v) whether the resource has ever previously had a Capacity Supply Obligation;

(vi) the location of the resource's interconnection;

(vii) the estimated Seasonal Qualified Capacity Values of the resource, as well as an estimate of any incremental Seasonal Qualified Capacity Values (in MW) (for Generating Capacity Resources and Import Capacity Resources);

(viii) the estimated total summer and winter demand reduction value (for Demand Capacity Resources and Distributed Energy Capacity Resources) or net injection capability values per facility (for Distributed Energy Capacity Resources);

(ix) a description of the resource, including (for Generating Capacity Resources and Import Capacity Resources) a general description of the resource's equipment configuration and a description of the resource technology type, and (for Demand Capacity Resources) a description of the resource's Demand Capacity Resource type and measure type, and (for Distributed Energy Capacity Resources) a description of the project and its configuration, including the types of generation and demand response composing the project, and (for

Generating Capacity Resources and Distributed Energy Capacity Resources comprising generation) a one-line diagram of the resource's configuration;

(x) for resources supported by an Internal Elective Transmission Upgrade, all unique project identifiers associated with the Internal Elective Transmission Upgrade;

(xi) for Generating Capacity Resources with a contract to export capacity from the New England Control Area during the Capacity Commitment Period, the interface over which the capacity will be exported and the contract associated with the export capacity;

(xii) Additional requirements for Import Capacity Resources, the interface over which the capacity will be imported and one of the following submissions documenting the source of the imported capacity, as further detailed in Section III.15.2.1.1.1: (i) documentation of a contract entered into before the Qualification Data Submission Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for one or more years encompassing the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iii) documentation for system-backed import capacity that the Import Capacity Resource will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load.

(xiii) Additional requirements for Demand Capacity Resources, as further detailed in Section III.15.2.1.1.2: resource technical and credit/financial contacts; Measurement and Verification Plan (for On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources); Load Zone and Dispatch Zone (for Active Demand Capacity Resources);

(xiv) Additional requirements for Distributed Energy Capacity Resources, as further detailed in Section III.15.2.1.1.3: expected nameplate capacity by technology type per facility; installation date of facilities that are part of the project and already constructed, installed, or in commercial operation; indication of whether the project elects Intermittent Power Resource treatment; resource technical and credit/financial contacts; Load Zone, Dispatch Zone and DRR Aggregation Zone;

(xv) Additional requirements for resources with capacity impacted by ambient air conditions between 90 degrees and 100 degrees, as further detailed in Section III.15.2.1.5; and

(xvi) Additional requirements for resources seeking ISO-estimated Seasonal Qualified Capacity Values, as further detailed in III.15.2.6(d): the Qualification Data Submission Package shall satisfy the technical data requirements associated with such resources and be supplemented with the as-built status of the resource on the date of the relevant Capacity Demonstration Deadline.

(b) By submitting the required qualification information, the Lead Market Participant certifies that a Capacity Offer from the resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 of Section II of the Tariff.

(c) The ISO may waive the submission of any information not required for evaluation of the resource.

III.15.2.1.1.1. Additional Import Capacity Resource Requirements.

Import Capacity Resources must be backed by one or more External Resources or by an external Control Area for the duration of the relevant Capacity Commitment Period. An external demand resource may not be an Import Capacity Resource. External nodes shall be established and mapped to Capacity Zones pursuant to the provisions in Attachment K to Section II of the Transmission, Markets and Services Tariff. For the purposes of the qualification process, all Import Capacity Resources shall be treated as if they had never previously participated as capacity and must submit the materials described pursuant to this Section III.15.2.1.1 for each Capacity Commitment Period for which the Import Capacity Resource seeks to qualify capacity. Import Capacity Resources backed by an External Control Area that does not have a Coordination Agreement with the ISO shall be ineligible to participate in the Annual Capacity Market. No single Import Capacity Resource may qualify capacity in excess of the external interface limits as described in Section III.12.10.

An Elective Transmission Upgrade with Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall have its external node modeled in the Annual Capacity Auction after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the Annual Capacity Auction qualification requirements of this Section III.15.2.1 and demonstration requirements of III.15.2.6. The Qualified Capacity of all Import Capacity Resources associated with an Elective Transmission Upgrade shall not exceed the Elective Transmission Upgrade's Capacity Network Import Capability.

Capacity Offers for Import Capacity Resources shall be subject to rationing except for Capacity Offers priced above the Capacity Offer Price Threshold for Import Capacity resources associated with an Elective Transmission Upgrade, which must obtain a Capacity Supply Obligation or not in whole unless the Capacity Offer indicated that it may be rationed as described in III.15.4.1.

III.15.2.1.1.1.1. Imports Backed by External Resources.

If the Import Capacity Resource will be backed by one or more External Resources, the Lead Market Participant shall submit a description of how the Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify. The description must indicate specifically which External Resources will back the Import Capacity Resource during the Capacity Commitment Period and contain the relevant historical performance data for each resource. If those External Resources are not owned or controlled directly by the Lead Market Participant, the description must include a commitment that the External Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.15.2.1.1.1.2. Imports Backed by an External Control Area.

If the Import Capacity Resource will be backed by an external Control Area, the Lead Market Participant shall submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the Import Capacity Resource.

III.15.2.1.1.1.3. Imports Crossing Intervening Control Areas.

Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) for imports crossing a single intervening Control Area, the Lead Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the Qualification Data Submission Deadline, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing; (2) for imports crossing more than one intervening Control Area, in addition to the requirements above, the Lead Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals,

by the Qualification Data Submission Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load; and (3) the Lead Market Participant entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.15.2.1.1.2. Additional Demand Capacity Resource Requirements.

A Demand Capacity Resource may be an Active Demand Capacity Resource, On-Peak Demand Capacity Resource, or Seasonal Peak Demand Capacity Resource, and may include an end-use customer facility with a Net Supply Capability of 5 MW or more only if the facility's Net Supply Capability does not exceed its Maximum Facility Load. Demand Capacity Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Capacity Resource. Demand Capacity Resources are not permitted to submit a Capacity Offer to import into or export out of the New England Control Area.

For a resource, or portion thereof, that never previously obtained a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction to qualify as an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource for the Capacity Commitment Period beginning June 1, 2028, the measure or measures contained in the resource must not have been in-service prior to June 1, 2024. For a resource, or portion thereof, that never previously obtained a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction to qualify as an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource in the Annual Capacity Auction or Monthly Reconfiguration Auction, as relevant, for or during the Capacity Commitment Period beginning June 1, 2029, and all Capacity Commitment Periods thereafter, the measure or measures contained in the resource must have been placed in-service or previously qualified as capacity no more than six months before the prior Annual Capacity Auction's Capacity Demonstration Deadline.

III.15.2.1.1.2.1. Measurement and Verification of Demand Capacity Resources.

(a) To demonstrate the demand reduction value of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, the Lead Market Participant of such a resource participating in the Annual Capacity Auction, Capacity Supply Obligation Bilaterals, or Monthly Reconfiguration Auctions shall submit to the ISO Measurement and Verification Documents in accordance with this Section III.15.2.1.1.2.1 and the ISO New England Manuals. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.15.2.1.1.2.1 and the ISO New England Manuals.

(b) Measurement and Verification Documents must demonstrate both availability and performance of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource in reducing demand coincident with Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours such that the reported monthly demand reduction value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manuals and ISO New England Operating Procedures. The Measurement and Verification Documents shall: (1) serve as the basis for the claimed demand reduction value of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource; (2) document the measurement and verification performed to verify the achieved demand reduction value of the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource; and (3) contain a projection of the On-Peak Demand Capacity Resource's or Seasonal Peak Demand Capacity Resource's demand reduction value for each month of the Capacity Commitment Period and, for those Demand Capacity Resources composed of energy efficiency measures, over the expected Measure Lives. An On-Peak Demand Capacity Resource's or Seasonal Peak Demand Capacity Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours. If an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource includes Distributed Generation, the Measurement and Verification Documents must describe the individual metering or metering protocol used to monitor and verify the output of the Distributed Generation, consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals.

(c) The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Annual Capacity Auction qualification process, as described in this Section III.15.2.1.1.2.1, and monthly Measurement and Verification data submitted during the Capacity Commitment Period. The monthly Measurement and Verification data shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan.

Such monthly Measurement and Verification data shall document the Lead Market Participant's total demand reduction value from both eligible pre-existing measures and new measures, and the Lead Market Participant's total demand reduction value from both eligible pre-existing measures and new measures, for all measures in operation as of the end of the previous month. The monthly Measurement and Verification data shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Lead Market Participants. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

(d) Lead Market Participants for On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources shall submit no less frequently than once per year, a statement certifying that the Demand Capacity Resource for which the Lead Market Participant is requesting compensation continues to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than ten Business Days before the Qualification Data Submission Deadline.

(e) For On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources comprising customer facilities with greater than or equal to 10 kW of demand reduction value per facility, Lead Market Participants shall maintain records of retail customers served, including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly demand reduction values. For On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources targeting customer facilities with under 10 kW of demand reduction value per facility, the Lead Market Participant shall maintain records as described above for customer facilities with greater than or equal to 10 kW of demand reduction value per facility, or shall maintain records of aggregated demand reduction values and measures installed by Load Zone and meter domain. Lead Market Participants shall maintain such records until the end of the Measure Life, or until the Demand Capacity Resource is retired or deactivated from the Annual Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

(f) The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Annual Capacity Auction qualification

process as described in Section III.15.2 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Lead Market Participant to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.15.2.1.1.3. Additional Distributed Energy Capacity Resource Requirements.

(a) Distributed Energy Capacity Resources. A facility connected at a point of interconnection that is 5 MW or greater cannot be a part of a Distributed Energy Capacity Resource. A Distributed Energy Capacity Resource comprises one or more Distributed Energy Resource Aggregations located in a single Capacity Zone and a single DRR Aggregation Zone, except that (a) a Settlement Only Distributed Energy Resource Aggregation may not participate in a Distributed Energy Capacity Resource with any other type of Distributed Energy Resource Aggregation, and (b) an end-use customer facility participating as part of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource with measures other than Energy Efficiency may not participate in a Distributed Energy Capacity Resource. Distributed Energy Capacity Resources are not permitted to submit a Capacity Offer to import into or export out of the New England Control Area. For purposes of this Section III.15.2.1.1.3: (i) if a facility is expected to interconnect at a point of interconnection, its net injection capability is the generation capability of the installed generation technology at the point of interconnection; (ii) if a facility is expected to interconnect at a Retail Delivery Point and does not plan to participate in the aggregation as a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation, the net injection capability is the lesser of the generation less the load profile measured at the location of the end-use customer meter or the amount the facility is contractually able to inject.

(b) Demand Response Resource in Distributed Energy Capacity Resources. If the Distributed Energy Capacity Resource includes Demand Response Resources, the completed Qualification Data Submission Package shall include the following additional information: the estimated summer and winter demand reduction values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses); the estimated total summer and winter demand reduction value of the Demand Response Resource (which must be consistent with the baseline calculation methodology in Section

III.8.2); and supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated demand reduction values.

(c) Net Injection of 5 MW or Greater. If the Distributed Energy Capacity Resource contains a Distributed Energy Resource Aggregation with a facility with net injection of 5 MW or greater at a Retail Delivery Point, then the completed Qualification Data Submission Package for such a resource shall include the following additional information: the Pnode and service address at which the end-use facility is located; nameplate MW and net injection capability; non-coincident peak load (MW) of the facility without generation; technology type; and the Market Participant's portion of generation requested to be included as Qualified Capacity.

(d) Net Injection Greater Than or Equal to 1 MW and less than 5 MW. If the Distributed Energy Capacity Resource contains a Distributed Energy Resource Aggregation with a facility that has net injection capability at the point of interconnection of 1 MW or greater and less than 5 MW, then the completed Qualification Data Submission Package for such a facility shall include the following additional information: distribution bus; technology type; nameplate MW; one-line diagram of the plant and station facilities, including any known transmission facilities; if the facility is intermittent, the requested contribution of Qualified Capacity and supporting site-specific data; if an interconnection agreement is required under state requirements, the date when the interconnection request was submitted and the status of that interconnection request.

III.15.2.1.2. Market Power Review.

Lead Market Participants seeking to qualify a Capacity Resource that has not previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or that is otherwise treated as if it had never done so pursuant to this Section III.15.2, must comply with the market power review provisions of Section III.A.21 by the Annual Capacity Auction Qualification Data Submission Deadline.

III.15.2.1.3. Capacity Commitment Period Election.

For the Annual Capacity Auctions for the 2028-2029, 2029-2030 and 2030-2031 Capacity Commitment Periods, a Lead Market Participant that has made the election in Section III.13.1.1.2.2.4 of the Forward Capacity Market rules with respect to a Capacity Resource must specify by the Qualification Data Submission Deadline whether it elects to continue to have the associated Capacity Supply Obligation and Capacity Clearing Price apply in Annual Capacity Auctions for the balance of the period permitted for

such Capacity Resource pursuant to Section III.13.1.1.2.2.4. Should a Lead Market Participant elect to terminate Section III.13.1.1.2.2.4 treatment for its Capacity Resource, it may not re-elect such treatment for any future Annual Capacity Auctions.

A Lead Market Participant that has made the election in Section III.13.1.1.2.2.4 of the Forward Capacity Market rules with respect to a Capacity Resource which has not achieved Capacity Market Commercial Operation as defined in Section III.15.2.6 of Market Rule 1 may not participate in the Annual Capacity Auction for the 2028-2029 Capacity Commitment Period and shall not have the previously elected Capacity Supply Obligation and Capacity Clearing Price apply for the 2028-2029 Capacity Commitment Period. Should such resource achieve Capacity Market Commercial Operation in time for participation in the Annual Capacity Auction for the 2029-2030 Capacity Commitment Period, or the Annual Capacity Auction for the 2030-2031 Capacity Commitment Period, it may elect to have the Capacity Supply Obligation and Capacity Clearing Price it received pursuant to Section III.13.1.1.2.2.4 apply for the balance of the period permitted for such Capacity Resource pursuant to Section III.13.1.1.2.2.4, and in no event after the Annual Capacity Auction for the 2030-2031 Capacity Commitment Period.

III.15.2.1.4. Material Deficiency in Data Submission.

In its review of a Lead Market Participant's data submission under this Section III.15.2.1, the ISO may consult with the Lead Market Participant, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO determines that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Lead Market Participant may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

In the event the ISO determines that a Lead Market Participant's data submission under Section III.15.2.1 is materially deficient, it shall notify the participant of such deficiencies at least ten Business Days prior to publication of the Advisory Seasonal Qualified Capacity Values, and the Lead Market Participant shall have five Business Days from the date of notification to cure the deficiencies. Should a Lead Market Participant fail to cure such deficiencies by the end of the cure period, it shall not be permitted to participate in the Annual Capacity Auction. In the event of such a rejection, the ISO shall provide the

Lead Market Participant with a written explanation of the reason for the rejection within ten Business Days of the close of the cure period.

III.15.2.1.5. Additional Qualification Requirements for Ambient Air Condition Impacts.

In the Qualification Data Submission Package, a Lead Market Participant may submit documentation indicating that a portion of its resource's capacity will not be physically available due to an ambient air condition. The size of such ambient air condition is calculated as the difference between the summer Qualified Capacity at 90 degrees and the rating of the resource at 100 degrees. The ISO shall verify during the qualification process the size of the ambient air condition.

III.15.2.2. Monthly Reconfiguration Auction Qualification.

For a resource that has not previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction to qualify as a Capacity Resource for the purpose of participation in a Monthly Reconfiguration Auction pursuant to Section III.15.5 or bilateral activities pursuant to Section III.15.6, prior to the Capacity Demonstration Deadline for the relevant month a Lead Market Participant must: (1) submit the Qualification Data Submission Package as described in Section III.15.2.1 (except for the information described at Section III.15.2.1.2) by the Capacity Demonstration Deadline for the relevant month, except that an Import Capacity Resource or a Resource seeking ISO-estimated Seasonal Qualified Capacity Values pursuant to Section III.15.2.6(d) must submit its Qualification Data Submission Package 30 calendar days prior to the Capacity Demonstration Deadline; and (2) complete a capacity demonstration pursuant to Section III.15.2.6.

III.15.2.3. Deliverability Review.

A Generating Capacity Resource, Active Demand Capacity Resource, Import Capacity Resource associated with an External Elective Transmission Upgrade, and Distributed Energy Capacity Resource must satisfy the deliverability review requirements described in this Section III.15.2.3 in order to qualify capacity for participation in an Annual Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction above the deliverability value associated with the resource's qualification for any previous Forward Capacity Auction, Annual Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction. None of the provisions of this Section III.15.2, supersedes, replaces, or satisfies any of the requirements of Schedules 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder.

III.15.2.3.1. Deliverability Review for Capacity Resources Associated with Generating Facilities or External Elective Transmission Upgrades Subject to Schedule 22, 23, or 25 of Section II of the Tariff.

A Generating Facility or External Elective Transmission Upgrade subject to Schedules 22, 23 or 25 of Section II of the Tariff must complete the applicable interconnection processes set forth therein and have been assigned, as applicable, either Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service, as necessary to support the delivery of the associated Capacity Resource's Qualified Capacity.

III.15.2.3.2. Deliverability Review for Capacity Resources Associated with Resources Not Subject to Schedule 22, 23, or 25 of Section II of the Tariff.

For a Generating Capacity Resource, Active Demand Capacity Resource, or Distributed Energy Capacity Resource not subject to Schedules 22, 23, or 25 of Section II of the Tariff, the ISO shall perform a deliverability review based on: (1) the information provided in the resource's Qualification Data Submission Package; and (2) the results of the ISO's most recent deliverability analysis, performed consistent with the criteria and conditions conducted as described in the ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that such a resource cannot deliver any of the requested incremental capacity, then the resource or incremental portion thereof shall not qualify for participation in the Capacity Market as reflected in the Seasonal Qualified Capacity Values issued pursuant to Section III.15.2.7; otherwise, the ISO shall determine that the requested Qualified Capacity of the Capacity Resource is deliverable, and the Capacity Resource shall be eligible to continue to proceed with the remainder of the processes described in this Section III.15.2.

III.15.2.4. Resources Previously Counted as Capacity.

Resources that have previously counted as capacity shall, for the purposes of Section III.15.2, be treated as if they had never previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction if: (1) there is a material change to the Capacity Resource as described in III.15.2.4.1, or (2) if a deactivated or retired resource seeks to re-enter the Capacity Market pursuant to III.15.2.4.2.

III.15.2.4.1. Material Change to a Capacity Resource.

(a) A Lead Market Participant that materially changes a Capacity Resource that has previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or plans to do so prior to the relevant Capacity Demonstration Deadline, may, by the relevant Qualification Data

Submission Deadline or monthly Capacity Demonstration Deadline, inform the ISO of that material change, update the information provided under Section III.15.2.1.1 to reflect the change to the Capacity Resource, and demonstrate its updated Commercial Capacity pursuant to Section III.15.2.6. The updated Qualified Capacity of the resource, accounting for the change, shall be calculated in accordance with Section III.15.3.1 for the subsequent Annual Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral. The Seasonal Qualified Capacity of a Capacity Resource that notifies the ISO of a material change but does not demonstrate pursuant to III.15.2.6 shall remain unmodified until demonstration of the material change occurs.

(b) For purposes of this Section III.15.2.4, a material change to a Capacity Resource is a change to the design or operating characteristics of the resource, including its interconnection facilities, that may have a significant effect on the reliability or operating characteristics associated with the Capacity Resource, and shall include, but not be limited to, changing the resource technology type, making a change to the Capacity Resource that increases or decreases the resource's Annual Qualified Capacity by greater than the lesser of 5 MW or 10 percent, or any change to the resource that requires a material modification to its interconnection agreement. No less than 30 calendar days prior to the Qualification Data Submission Deadline or Monthly Capacity Demonstration Deadline, as relevant, a Lead Market Participant may request, and the ISO shall within 20 calendar days provide, a determination regarding whether a change qualifies as a material change to a Capacity Resource pursuant to this Section III.15.2.4 and requires submission of the materials required pursuant to Section III.15.2.1.1.

III.15.2.4.2. Treatment of Previously Deactivated or Retired Resources.

In order to qualify for participation in the Capacity Market, a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) must: (1) have reached its deactivation date and reduced its Capacity Network Resource Capability pursuant to Section II.48.3; (2) if the resource was compensated for delaying deactivation through a Commission-approved cost-of-service agreement, have refunded to the ISO all costs subject to refund under the claw-back provision set forth in Section II.54.1; and (3) have satisfied the provisions of Section III.15.2, including submission of the Qualification Data Submission Package described in Section III.15.2.1 and completed the capacity interconnection service requirements described in Section III.15.2.3, as if the resource had never previously received a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction.

III.15.2.5. Calculation of Advisory Qualified Capacity Values.

Following the Qualification Data Submission Deadline, by a date in the month of February published on the Capacity Auction Calendar, the ISO shall calculate and provide to Lead Market Participants summer and winter Advisory Qualified Capacity Values for each resource that has met the data submission requirements in Section III.15.2.1. The Advisory Qualified Capacity Values of any resource that has not previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or is otherwise treated as if it had not done so, shall equal its demonstrated Commercial Capacity determined in accordance with Section III.15.2.6; except that in the event that a resource has not yet demonstrated a portion of its Commercial Capacity, its Advisory Qualified Capacity Values shall equal the sum of its Commercial Capacity and the estimated incremental Seasonal Qualified Capacity Values of the resource as submitted pursuant to Section III.15.2.1. For all other resources, the Advisory Qualified Capacity Values shall equal the Capacity Resource's summer and winter Qualified Capacity as calculated pursuant to Section III.15.3.

During the period beginning with the ISO's issuance of Advisory Qualified Capacity Values and ending with the conclusion of the Annual Capacity Auction, any change to a capacity resource or the information submitted in a Qualification Data Submission Package shall not impact the resource's Seasonal Qualified Capacity Values for that Annual Capacity Auction unless the change has already been accounted for in the submitted Qualification Data Submission Package, or is made pursuant to Section III.15.2.1.4 or Section III.15.2.7.

III.15.2.6. Capacity Commercial Operation Demonstration Requirement.

To participate in an Annual Capacity Auction, Monthly Reconfiguration Auctions, or a Capacity Supply Obligation Bilateral transaction, a Capacity Resource must first demonstrate that its capacity is commercially operational by meeting the demonstration requirements in this Section III.15.2.6 by the applicable Capacity Demonstration Deadline. A resource that meets the demonstration requirements of this Section III.15.2.6 shall be deemed to have achieved Capacity Market Commercial Operation.

(a) Demonstration must be completed (i) prior to a Capacity Resource's initial participation in the Annual Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction, and (ii) when a Capacity Resource that has previously received a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction materially changes or reactivates pursuant to Section III.15.2.4.

(b) The Capacity Demonstration Deadline for each Annual Capacity Auction shall be during the month of April preceding the relevant Annual Capacity Auction, as published on the Capacity Auction

Calendar; for each Monthly Reconfiguration Auction and Capacity Supply Obligation Bilateral window, the Capacity Demonstration Deadline shall precede the relevant Obligation Month by approximately two weeks, as published on the Capacity Auction Calendar.

(c) To demonstrate commercial capacity, a resource must perform an audit by the relevant Capacity Demonstration Deadline, using the following audit requirements:

(i) For Generating Capacity Resources that are not Intermittent Power Resources, each Generator Asset must perform an Establish Claim Capability Audit pursuant to Section III.1.5.1.2, provide the data described in ISO New England Operating Procedure No. 23, and have its audit value become effective pursuant to Section III.1.5.1.2(d)(iv).

(ii) For Generating Capacity Resources that are Intermittent Power Resources, each Generator Asset must perform a Seasonal Claim Capability Audit pursuant to Section III.1.5.1.3, provide the data described in ISO New England Operating Procedure No. 23, and have its audit value become effective pursuant to Section III.1.5.1.3(i).

(iii) For Active Demand Capacity Resources, each Demand Response Asset must perform a Seasonal DR Audit pursuant to III.1.5.1.3.1, as specified by season in III.15.7.1.5.3(c), requested by the Lead Market Participant, and have its audit value become effective pursuant to Section III.1.5.1.3.1(m).

(iv) For Demand Capacity Resources that are not Active Demand Capacity Resources, each Demand Capacity Resource must perform a Passive DR Audit pursuant to III.15.7.1.5.4, as specified by season in III.15.7.1.5.3(c), at the request of the Lead Market Participant, and have its audit value become effective pursuant to Section III.15.7.1.5.4(f).

(v) For Distributed Energy Capacity Resources, each asset comprising the Distributed Energy Capacity Resource must meet the demonstration requirement in sub-sections (i) through (iii) above for its corresponding asset type.

(vi) For Import Capacity Resources, demonstration is achieved through provision of performance data in the resource's Qualification Data Submission Package in accordance with Section III.15.2.1, except that Import Capacity Resources associated with an external Elective

Transmission Upgrade must demonstrate the ability to transfer power between regions pursuant to Schedule 25, Article 6.

(d) For those resources identified in Sections III.15.2.6(c)(ii), III.15.2.6(c)(iv), and III.15.2.6(c)(v) providing asset-level meter-based performance data by the Capacity Demonstration Deadline that is, as determined by the Lead Market Participant, of insufficient duration to establish accurate Seasonal Qualified Capacity Values, or for a period inconsistent with the audit described in Section III.15.2.6(c), the Lead Market Participant may request that the ISO determine Seasonal Qualified Capacity Values based on the lesser of: (1) the Seasonal Qualified Capacity Values requested for qualification by the Lead Market Participant; or (2) the Seasonal Qualified Capacity Values estimated by the ISO. In no instance shall the Seasonal Qualified Capacity Values developed pursuant to this Section III.15.2.6(d) exceed a resource's seasonal Capacity Network Resource Interconnection Service, or its equivalent.

The ISO-estimated Seasonal Qualified Capacity Values shall be based on technical data requirements for recently commercial resources identified in the Qualification Data Submission Package. The Qualification Data Submission Package of resources seeking ISO-estimated Seasonal Qualified Capacity Values shall include a description of the as-built status of the resource at time of submission, including whether the resource is fully or partially operational. For those resources seeking ISO-estimated Seasonal Qualified Capacity Values, the Qualification Data Submission Package must be submitted to the ISO by the Lead Market Participant by the Qualification Data Submission Deadline for the Annual Capacity Auction, or 30 days prior to the relevant monthly Capacity Demonstration Deadline, with the submission updated at the time of the Capacity Demonstration Deadline to reflect the as-built status of the resource. Resources satisfying the provisions of this Section III.15.2.6(d) shall be deemed to have demonstrated Commercial Capacity.

Resources seeking ISO-estimated Seasonal Qualified Capacity Values that have completed the relevant audit described in III.15.2.6(c) for only one season may elect to use the ISO-estimated Seasonal Qualified Capacity Values for one or both seasons. The ISO-estimated Seasonal Qualified Capacity Values may constitute a resource's Seasonal Qualified Capacity Value for up to one year after issuance, but shall be valid for no longer than one year after a resource becomes fully operational. A Lead Market Participant may request replacement of ISO-estimated Seasonal Qualified Capacity Values once the relevant seasonal audit has been completed.

III.15.2.7. Seasonal Qualified Capacity Values and Challenge Process.

(a) Following the April Capacity Demonstration Deadline, for each Capacity Resource qualified to participate in an Annual Capacity Auction, the ISO shall notify the Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity, calculated in accordance with Section III.15.3, and the Load Zone in which the resource is located. This notification will be provided by the Seasonal Qualified Capacity Notification Date specified in the Capacity Auction Calendar.

(b) If the Lead Market Participant believes that the ISO has made a mathematical error in calculating the summer Qualified Capacity or winter Qualified Capacity for a Capacity Resource, then the Lead Market Participant must notify the ISO within five calendar days of the Seasonal Qualified Capacity Notification Date.

(c) If a Capacity Resource's summer Qualified Capacity has been subject to a significant decrease pursuant to Section III.15.3.6, the Lead Market Participant may submit a restoration plan in accordance with Section III.15.3.6(b) within five calendar days of the Seasonal Qualified Capacity Notification Date.

(d) The ISO shall notify the Lead Market Participant of the outcome of any challenge submitted under (b) above or of its determination regarding the sufficiency of a restoration plan submitted under (c) above, by the date specified in the Capacity Auction Calendar for such responses. In assessing the sufficiency of a restoration plan, the ISO shall determine whether the plan provides sufficient information to support the reasonable likelihood of the resource providing capacity consistent with its summer Qualified Capacity value by the start of the Capacity Commitment Period.

III.15.2.8. Offers Composed of Separate Resources (Composite Offers).

Separate resources seeking to participate together in an Annual Capacity Auction shall submit a Composite Offer Form no later than the Composite Offer Deadline, which shall be approximately two business days prior to the auction as specified in the Capacity Auction Calendar, with the exception that Distributed Energy Capacity Resources may not participate in composite offers. Composite offers may not be modified or withdrawn after the Composite Offer Deadline. Composite offers must meet the following conditions:

(a) In all months of the summer period of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources combined meet the amount of the offer in all

months of the winter period; and (ii) to combine for a month, that month must be a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of a composite offer must qualify in accordance with all of the provisions of Section III.15.2 applicable to that resource type. A composite offer participates in the Annual Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period.

(c) The summer Qualified Capacity of a composite offer shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.15.3.7 shall apply, even where one or more of the resources that are part of the offer composed of separate resources is an Intermittent Power Resource. If the winter capacity of the composite offer in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

(d) Composite offers are subject to the locational restrictions specified in the following table:

		Location of Summer Resource			
		Import-Constrained Capacity Zone	Rest-of-Pool Capacity Zone	Export-Constrained Capacity Zone	Nested Export-Constrained Capacity Zone
Location of Winter Resource	Import-Constrained Capacity Zone	Eligible (within same Capacity Zone)	Eligible	Eligible	Eligible
	Rest-of-Pool Capacity Zone	Ineligible	Eligible	Eligible	Eligible
	Export-Constrained Capacity Zone	Ineligible	Ineligible	Eligible (within same Capacity Zone)	Eligible (within same Capacity Zone where nested export-constrained Capacity Zone is located)

	Nested Export-Constrained Capacity Zone	Ineligible	Ineligible	Ineligible	Eligible (within same Capacity Zone)

III.15.2.9. Self-Supplied Capacity.

Where a load serving entity elects to designate all or a portion of its Capacity Load Obligation as self-supplied, the load serving must make such designation to the ISO during the self-supply designation window, as published in the Capacity Auction Calendar on the ISO's website. The load serving entity's designation shall specify the MW amount and Lead Market Participant providing the self-supplied capacity. During the Annual Capacity Auction Offer Window, the Lead Market Participant supplying such capacity shall confirm the load serving entity's self-supply designation by specifying each Self-Supplied Capacity Resource and the MW amount of self-supplied capacity in its Capacity Offer. A Generating Capacity Resource or an Import Capacity Resource may be designated as a Self-Supplied Capacity Resource. A Distributed Energy Capacity Resource may only designate its net injection capability as a Self-Supplied Capacity Resource. All self-supplied capacity shall be subject to the eligibility and locational requirements in this Section III.15.2.9. If designated as a Self-Supplied Capacity Resource the resource will clear in the Annual Capacity Auction as described in Section III.15.4 and, with the exception of demand programs for Self-Supplied Capacity Resources, shall offset an equal amount of the load serving entity's Capacity Load Obligation in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Capacity Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.15.2. All designations as a Self-Supplied Capacity Resource in the Annual Capacity Auction qualification process are binding.

III.15.2.9.1. Self-Supplied Capacity Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied Capacity Resource, it shall also maintain its status as a Generating Capacity Resource, Import Capacity Resource, or Distributed Energy Capacity Resource and must satisfy the Annual Capacity Auction qualification process requirements set forth in the remainder of Section III.15.2 applicable to that resource type, in addition to the requirements of this Section III.15.2.9.1. Where a Capacity Offer composed of separate resources is submitted for a Self-Supplied Capacity Resource, all of the requirements and deadlines specified in Section III.15.2.8 shall apply to that offer, in addition to the requirements of this Section III.15.2.9. The total quantity of capacity that a load serving entity designates as self-supplied capacity

may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period, which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied Capacity Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.15.2.9.2. Locational Requirements for Self-Supplied Capacity Resources.

In order to participate in the Annual Capacity Auction as a Self-Supplied Capacity Resource for a load in an import-constrained Capacity Zone, the Self-Supplied Capacity Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied Capacity Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Annual Capacity Auction as a Self-Supplied Capacity Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied Capacity Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.15.2.10. Publication of Annual Qualified Capacity Values for Annual Capacity Auction.

The ISO shall provide Annual Qualified Capacity values to Lead Market Participants of each Capacity Resource participating in an Annual Capacity Auction one business day before the opening of the Annual Capacity Auction Offer Window.

III.15.2.11. Publication of Offer Information.

(a) For each Capacity Offer, the quantity and Load Zone (or interface, as applicable) in which the resource is located will be published to the ISO's website no later than 15 days after the Annual Capacity Auction is conducted.

(b) For Capacity Offers from Import Capacity Resources, the name of submitter, quantity, and interface shall be published to the ISO's website no later than 15 days after the Annual Capacity Auction is conducted.

(c) The name of each Lead Market Participant submitting Capacity Offers, as well as the number of Capacity Offers submitted by each Lead Market Participant, shall be published to the ISO's website no later than 15 calendar days after the issuance of Advisory Qualified Capacity Values. Authorized Persons

of Authorized Commissions will be provided confidential access to full information about posted Capacity Offers upon request pursuant to Section 3.3 of the ISO New England Information Policy.

III.15.3. Capacity Resource Accreditation.

Pursuant to the provisions of this Section III.15.3, the ISO shall determine a summer Qualified Capacity, a winter Qualified Capacity, an Annual Qualified Capacity and, where applicable, a Monthly Qualified Capacity for each Generating Capacity Resource, Import Capacity Resource, Demand Capacity Resource, and Distributed Energy Capacity Resource. A Capacity Resource's Seasonal Qualified Capacity Values shall not exceed its seasonal Capacity Network Resource Interconnection Service or equivalent, or Capacity Network Import Interconnection Service, as applicable. Qualified Capacity for resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall not exceed the resource's highest previously received Capacity Supply Obligation unless the resource has demonstrated and qualified the additional capacity pursuant to Section III.15.2.4.1.

Qualified Capacity values for resources that have never previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall be calculated pursuant to Section III.15.3.1. Qualified Capacity for resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall be calculated pursuant to Sections III.15.3.2 through III.15.3.5.

III.15.3.1. Qualified Capacity for Resources Never Previously Counted as Capacity.

III.15.3.1.1. Resources Never Previously Counted as Capacity.

The summer and winter Qualified Capacity of a Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or is otherwise treated as such pursuant to the terms of this Section III.15, shall be determined in accordance with the capacity demonstration requirements set forth in Section III.15.2.6, as specified below.

To determine the Seasonal Qualified Capacity Values of a Generating Capacity Resource that is not an Intermittent Power Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant to Section III.15.2.6(c)(i), the ISO shall use the Section III.1.5.1.2(c) audit results. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3 and III.15.3.2.4, respectively.

To determine the Seasonal Qualified Capacity Values of a Generating Capacity Resource that is an Intermittent Power Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant Section III.15.2.6(c)(ii), the ISO shall use the Section III.1.5.1.3 audit results. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3 and Section III.15.3.2.4, respectively.

To determine the Seasonal Qualified Capacity Values of an Active Demand Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(iii), the ISO shall use the Section III.1.5.1.3.1 audit results. To determine the Seasonal Qualified Capacity Values of a Demand Capacity Resource other than an Active Demand Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(iv), the ISO shall use the Section III.15.7.1.5.4 audit results. The annual and Monthly Qualified Capacity of such resources shall be determined pursuant to Sections III.15.3.4.2 and III.15.3.4.3, respectively.

To determine the Seasonal Qualified Capacity Values of a Distributed Energy Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(v), the ISO shall use the audit results specified therein for the corresponding asset type. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to III.15.3.5.2 and III.15.3.5.3, respectively.

To determine the Seasonal Qualified Capacity Values of an Import Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant Section III.15.2.6(c)(vi), the ISO shall use the performance data results specified therein. The annual and monthly Qualified Capacity of such a resource shall be determined pursuant to III.15.3.3.

To determine the Seasonal Qualified Capacity Values of a resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and that has elected to demonstrate commercial capacity pursuant Section III.15.2.6(d), the ISO shall use the values developed pursuant to Section III.15.2.6(d). The annual Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3, Section III.15.3.4.2, or Section III.15.3.5.2, as applicable to

the relevant resource type. The Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.4, III.15.3.4.3, or Section III.15.3.5.3, as applicable to the relevant resource type.

III.15.3.2 Qualified Capacity for Generating Capacity Resources.

The summer, winter, annual, and monthly Qualified Capacity for Generating Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.2.

III.15.3.2.1. Summer Qualified Capacity.

(a) For the purpose of Annual Capacity Auction qualification, the summer Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the Capacity Demonstration Deadline each year, with only positive summer ratings included in the median calculation. Where a Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Generating Capacity Resource shall be equal to the median of all the Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the Capacity Demonstration Deadline of each year, with only positive summer ratings included in the median calculation.

(b) For the purpose of Annual Capacity Auction qualification, the summer Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the average of the median of the Intermittent Power Resource's net output during Summer Intermittent Reliability Hours for each of the previous five summer periods. If there are fewer than five full summer periods since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation, the summer Qualified Capacity of such resource shall be the average of the median of the Intermittent Power Resource's net output during Summer Intermittent Reliability Hours in each of the previous summer periods, or portion thereof, since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation. The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which there was a system-wide Capacity Scarcity Condition, and for Intermittent Power Resources in an import-constrained Capacity Zone, all summer period hours in which there was a Capacity Scarcity Conditions in that Capacity Zone.

III.15.3.2.2. Winter Qualified Capacity.

(a) For the purpose of Annual Capacity Auction qualification, the winter Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the Capacity Demonstration Deadline of each year, with only positive winter ratings included in the median calculation. Where a Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Generating Capacity Resource shall be equal to the median of all the Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the Capacity Demonstration Deadline of each year, with only positive winter ratings included in the median calculation.

(b) For the purpose of Annual Capacity Auction qualification, the winter Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the average of the median of the Intermittent Power Resource's net output during Winter Intermittent Reliability Hours for each of the previous five summer periods. If there are fewer than five full summer periods since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation, the winter Qualified Capacity of such resource shall be the average of the median of the Intermittent Power Resource's net output during Winter Intermittent Reliability Hours in each of the previous winter periods, or portion thereof, since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation. The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which there was a system-wide Capacity Scarcity Condition, and for Intermittent Power Resources in an import-constrained Capacity Zone, all winter period hours in which there was a Capacity Scarcity Conditions in that Capacity Zone.

III.15.3.2.3. Annual Qualified Capacity.

The Annual Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The Annual Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.15.3.2.4. Monthly Qualified Capacity.

The Monthly Qualified Capacity of a Generating Capacity Resource shall be the resource's most recent Seasonal Claimed Capability value for the season applicable to the relevant month; for those Generating Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

III.15.3.3. Qualified Capacity for Import Capacity Resources.

The summer, winter, annual, and monthly Qualified Capacity of an Import Capacity Resource backed by an External Control Area shall be based on the values and data submitted during the qualification process, subject to ISO review and verification. The summer, winter, annual, and monthly Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be based on the data submitted during the qualification process, subject to ISO review and verification, and calculated based on the summer and winter Qualified Capacity of the resources underlying the Import Capacity Resource, in accordance with Sections III.15.3.2.1 and III.15.3.2.2.

III.15.3.4. Qualified Capacity for Demand Capacity Resources.

The summer, winter, annual, and monthly Qualified Capacity for Demand Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.4.

III.15.3.4.1. Summer and Winter Qualified Capacity.

(a) For Demand Capacity Resources composed of Energy Efficiency measures, the summer (or winter, as applicable) Qualified Capacity shall equal the sum of the summer (or winter, as applicable) demand reduction values of the installed Energy Efficiency measures as of the Capacity Demonstration Deadline (excluding any capacity that will retire or deactivate, or whose Measure Life will expire, prior to the start of the applicable season of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses).

(b) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the summer and winter Qualified Capacity shall equal the median of the resource's Seasonal DR Audit value or Passive DR Audit value from the five most recent years, for the relevant season, increased by average avoided peak transmission and distribution losses. Where a Demand Capacity Resource has fewer than five summer or winter Seasonal Audit Values, as applicable, then the summer (or winter) Qualified Capacity for that Demand Capacity Resource shall be equal to the median of all the resource's previous

summer (or winter) Seasonal Audit Values, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation.

III.15.3.4.2. Annual Qualified Capacity.

The Annual Qualified Capacity of a Demand Capacity Resource shall equal the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.15.3.4.3 Monthly Qualified Capacity.

The Monthly Qualified Capacity of a Demand Capacity Resource, other than a resource composed of Energy Efficiency measures, shall equal its most recent Seasonal DR Audit value or Passive DR Audit value for the season applicable to the relevant month; for those Demand Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

The Monthly Qualified Capacity of a Demand Capacity Resource composed of Energy Efficiency measures shall equal the most recently-determined summer or winter demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire, deactivate, or whose Measure Life will expire, prior to the start of the relevant Obligation Month, and increased by average avoided peak transmission and distribution losses).

III.15.3.5. Qualified Capacity of Distributed Energy Capacity Resources.

The summer, winter, annual, and monthly Qualified Capacity for Distributed Energy Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.5.

III.15.3.5.1. Summer and Winter Qualified Capacity.

The summer (or winter, as applicable) Qualified Capacity of a Distributed Energy Capacity Resource that is not an Intermittent Power Resource shall equal the median of the resource's summer (or winter) Seasonal Audit Value from the five most recent years, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation. Where a Distributed Energy Capacity Resource has fewer than five summer (or winter) Seasonal Audit Values, then the summer (or winter) Qualified Capacity for that Distributed Energy Capacity Resource shall be

equal to the median of the resource's previous summer (or winter) Seasonal Audit Values, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation.

The summer or winter Qualified Capacity of Distributed Energy Capacity Resources that are Intermittent Power Resources shall be determined in accordance with the rules for Generating Capacity Resources that are Intermittent Power Resources in Section III.15.3.2.

III.15.3.5.2. Annual Qualified Capacity.

Annual Qualified Capacity for a Distributed Energy Capacity Resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, unless the Distributed Energy Capacity Resource is an Intermittent Power Resource, in which case the Annual Qualified Capacity shall be equal to the resource's summer Qualified Capacity.

III.15.3.5.3. Monthly Qualified Capacity.

The Monthly Qualified Capacity of a Distributed Energy Capacity Resource shall equal the most recent Seasonal DECR Audit for the season applicable to the relevant month; for those Distributed Energy Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

III.15.3.6. Adjustment for Significant Decreases in Capacity.

For a Generating Capacity Resource, Import Capacity Resource backed by an External Resource, Distributed Energy Capacity Resource, or Demand Capacity Resource, if the most recent summer Seasonal Claimed Capability rating, summer season Import Capacity Resource performance data submitted pursuant to Section III.15.2.1.1.1, summer Seasonal DECR Audit Value, summer Seasonal DR Audit Value, or summer Passive DR Audit Value as of the Annual Capacity Auction's Capacity Demonstration Deadline is below the resource's Qualified Capacity by more than the threshold defined in the following formula:

$$Threshold = min[max(10\% \times QC_{Summer}, 2\ MW), 10\ MW]$$

Where,

QC_{Summer} = the resource's summer Qualified Capacity

then the Lead Market Participant must elect one of the two treatments set forth in this Section III.15.3.6 by the close of the Seasonal Qualified Capacity Challenge and Restoration Plan Submission Window. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.15.3.6(b) and fails to meet the associated requirements, then the treatment described in Section III.15.3.6(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Annual Capacity Auction only, to have the resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability rating, summer Seasonal DECR Audit Value, Seasonal DR Audit Value, or Passive DR Audit Value as of the Capacity Demonstration Deadline, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) A Lead Market Participant may elect: (i) to submit a restoration plan describing the measures that will be taken and showing that the Generating Capacity Resource, Import Capacity Resource backed by an External Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section III.15.3.2, Section III.15.3.3, Section III.15.3.4, or Section III.15.3.5 by the start of the relevant Capacity Commitment Period; and (ii) to have the Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section III.15.3.2, Section III.15.3.3, Section III.15.3.4, or Section III.15.3.5 for the Annual Capacity Auction. The ISO shall review submitted restoration plans in accordance with the requirements and timelines set forth in Section III.15.2.7.

III.15.3.7. Resources Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where a Generating Capacity Resource (other than an Intermittent Power Resource), Demand Capacity Resource, or Import Capacity Resource has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.15.3, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, in accordance with Section III.15.2.8; or (ii) have its Annual Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

Where a Distributed Energy Capacity Resource (other than an Intermittent Power Resource) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this

Section III.15.3, then that resource must have its Annual Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

III.15.4. Annual Capacity Auction.

III.15.4.1 Capacity Offers.

Lead Market Participants submitting Capacity Offers in the Annual Capacity Auction shall submit Capacity Offers for the Capacity Commitment Period associated with the Annual Capacity Auction as specified in this Section III.15.4.1.

(a) Each Capacity Offer shall be associated with a Capacity Resource for which an Annual Qualified Capacity value has been established for the Annual Capacity Auction through the Annual Capacity Auction qualification process set forth in Sections III.15.2 and III.15.3.

(b) Capacity Offers must be submitted during the Annual Capacity Auction Offer Window, the dates of which will be specified as published in the Capacity Auction Calendar. Capacity Offers are not considered final until the close of the Annual Capacity Auction Offer Window and may be amended or corrected as necessary until such time as the window closes.

(c) If a Lead Market Participant fails to submit a Capacity Offer for a resource subject to the requirements of Section III.A.22.1, the ISO shall enter a Capacity Offer for the resource into the Annual Capacity Auction in accordance with Section III.A.22.1(d).

(d) Each Capacity Offer must specify at least one price-quantity pair, which consists of one price, denominated in $/kW-month to an accuracy of at most three digits to the right of the decimal point, and a quantity value, expressed in MW to an accuracy of up to three decimal places. The Capacity Offer may specify up to ten price-quantity pairs, where each such pair represents the total amount of capacity offered from the Capacity Resource at the price specified. If more than one price-quantity pair is submitted, the price-quantity pairs must specify prices and quantity values in such a way that, when the price-quantity pairs are ordered from lowest price to highest price, the quantity value in each price-quantity pair increases with each successive, higher-priced price-quantity pair. The price-quantity pair with the greatest specified price must include the Capacity Resource's total Annual Qualified Capacity. The Capacity Offer must not contain any offer prices less than $0.00/kW-month or greater than the Capacity Auction Offer Price Cap, unless otherwise allowed pursuant to Section III.A.22.2.3 and subsection (e) of this Section III.15.4.1 or required by Section III.A.21 and subsection (f) of this Section III.15.4.1. The Capacity Offer must not specify a total MW quantity value that exceeds the Capacity Resource's Annual Qualified Capacity.

(e) A price-quantity pair in a Capacity Offer must not specify a price above the Capacity Offer Price Threshold, except under the following circumstances:

(i) the Lead Market Participant for the Capacity Resource submitted the price-quantity pair to the Internal Market Monitor as part of a Proposed Capacity Offer, pursuant to Section III.A.22.2.2;

(ii) the Internal Market Monitor determined an Allowable Capacity Offer Price relative to the price-quantity pair pursuant to Section III.A.22.2.3; and

(iii) the specified price in the Capacity Offer does not exceed the price specified in the price-quantity pair reviewed by the Internal Market Monitor.

(f) For capacity included in a Capacity Offer that is subject to a Capacity Offer Floor Price pursuant to Section III.A.21.3, the price specified must not be less than the Capacity Offer Floor Price.

(g) A Capacity Offer may specify a Rationing Minimum Limit up to which the offer may not be rationed and must be accepted or rejected in whole. Without such indication, offers shall be rationable up to the total MW quantity in the offer that is priced at or below the Capacity Offer Price Threshold, subject to the auction clearing constraint described in Section III.15.4.2.2(d). The lowest priced price-quantity pair in a Capacity Offer that specifies a Rationing Minimum Limit must specify a quantity value equal to or greater than the specified Rationing Minimum Limit. Notwithstanding the foregoing, a Capacity Offer for an Import Capacity Resource may only specify a Rationing Minimum Limit pursuant to this subsection (g) if the Import Capacity Resource is associated with an Elective Transmission Upgrade, as described in Section III.15.2.1.1.1.

(h) If the Capacity Offer specifies any price above the Capacity Offer Price Threshold, the Capacity Offer may elect to have the Above-Threshold Offer Segment be treated as rationable, subject to any Rationing Minimum Limit specified pursuant to subsection (g). Without such an election, the Above-Threshold Offer Segment will be treated as non-rationable and accepted or rejected in whole. Notwithstanding the foregoing, a Capacity Offer for an Import Capacity Resource may only elect rationability for the Above-Threshold Offer Segment pursuant to this subsection (h) if the Import

Capacity Resource is associated with an Elective Transmission Upgrade, as described in Section III.15.2.1.1.1.

(i) In order to give effect to a self-supply designation made by a load serving entity pursuant to Section III.15.2.9 for any portion of the Capacity Resource's Annual Qualified Capacity, the Capacity Offer for such resource must (i) identify the load serving entity for which its capacity will serve as self-supplied capacity and the MW quantity of self-supplied capacity and (ii) include a price-quantity pair with an offer price of $0.00/kW-month that includes the amount of such capacity, unless such capacity is subject to a Capacity Offer Floor Price. If the self-supplied capacity is subject to a Capacity Offer Floor Price, then the price specified in the price-quantity pair including the self-supplied capacity must equal the Capacity Offer Floor Price.

(j) A Capacity Offer for a Generating Capacity Resource with a contract to export capacity during the Capacity Commitment Period must specify an Export Offer Segment and the interface over which the Export Offer Segment will be exported.

(k) A Lead Market Participant for a Capacity Resource that is subject to delayed deactivation pursuant to Sections II.52 and II.53 shall not enter a Capacity Offer for any capacity supplied by the Capacity Resource that is subject to delayed deactivation. The ISO shall enter such Capacity Resource's capacity subject to delayed deactivation into the Annual Capacity Auction at a price of $0.00/kW-month.

(l) If a prior multi-year Capacity Supply Obligation and Capacity Clearing Price election for the Capacity Resource had been made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 for a Forward Capacity Auction, the Capacity Offer submitted for such Capacity Resource must include a price-quantity pair with an offer price of $0.00/kW-month that includes the total amount of the resource's capacity that cleared subject to such election.

III.15.4.2. Conduct of the Annual Capacity Auction.

The ISO shall determine Capacity Supply Obligations and Capacity Clearing Prices for the Capacity Commitment Period by conducting the Annual Capacity Auction as described in this Section III.15.4.2.

III.15.4.2.1. Replacement of Specified Prices for Mitigation Purposes.

After the Annual Capacity Auction Offer Window, the ISO shall replace specified prices in submitted Capacity Offers as necessary, pursuant to Section III.A.22.2.4(c). Any such adjusted Capacity Offers shall be inputs for the Annual Capacity Auction.

III.15.4.2.2. Clearing of the Annual Capacity Auction.

(a) In determining Capacity Supply Obligations and Capacity Clearing Prices, the ISO shall employ an optimization algorithm that is designed to maximize social surplus in order to clear Capacity Offers, capacity entered into the auction by the ISO as described in Section III.15.4.1(k), and any Proxy Capacity Offers against the capacity demand curves calculated in accordance with Section III.15.1.1. In clearing Capacity Offers, the optimization algorithm shall take into account, as applicable, the inputs and constraints set forth in this Section III.15.4.2.2.

(b) The optimization algorithm shall take into account the following: (i) all price-quantity pairs in Capacity Offers for the Annual Capacity Auction submitted pursuant to Section III.15.4.1, subject to any adjustments made pursuant to Section III.15.4.2.1 and the constraint described in subsection (c) of this Section III.15.4.2.1; (ii) any Rationing Minimum Limits and rationability elections specified in Capacity Offers pursuant to Section III.15.4.1(g) and Section III.15.4.1(h), respectively; (iii) capacity from a Capacity Resource subject to delayed deactivation pursuant to Sections II.52 and II.53 at a default price of $0.00/kW-month; (iv) the set of distinct Capacity Zones determined to be modeled in the Annual Capacity Auction pursuant to Section III.12.4; (v) the System-Wide Capacity Demand Curve calculated in accordance with Section 15.1.1.1; (vi) any Capacity Zone Demand Curves for import-constrained and export-constrained Capacity Zones, calculated in accordance with Sections 15.1.1.2 and 15.1.1.3, respectively; (vii) external interface limits calculated pursuant to Section III.12.10; and (viii) any Proxy Capacity Offers for the Annual Capacity Auction as determined pursuant to Section III.A.24.7, which shall be treated as non-rationable.

(c) The optimization algorithm shall not take into account price-quantity pairs in Capacity Offers that specify a price that exceeds the Capacity Auction Offer Price Cap.

(d) Capacity entered into the Annual Capacity Auction at a price of $0.00/kW-month shall clear the auction.

(e) A Capacity Offer that specifies a Rationing Minimum Limit pursuant to Section III.15.4.1(g) shall not clear at quantities less than the specified Rationing Minimum Limit, and Above-Threshold Offer

Segments that are non-rationable pursuant to Section III.15.4.1(h) shall not clear at quantities less than the MW quantity of the segment.

(f) For an Export Offer Segment specified in a Capacity Offer that indicates a Generating Capacity Resource's contract to export capacity over an external interface connected to an import-constrained Capacity Zone from another Capacity Zone, or over an external interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone, the ISO shall model the Export Offer Segment as though that quantity of capacity were located in the Capacity Zone where the external interface identified in the Capacity Offer is located and adjust Capacity Zone Demand Curves as necessary to reflect such modeling.

(g) In determining the clearing result that accounts for auction inputs and satisfies all applicable constraints, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including clearing results where a Capacity Offer with a specified price below the Capacity Clearing Price does not clear.

(h) Where the clearing of the Annual Capacity Auction either system-wide or in a single Capacity Zone results in a tie (that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs), the following rules shall apply in sequence, as necessary, to determine clearing: (i) if multiple Capacity Offers may be rationed, they will be rationed proportionately; and (ii) the Capacity Offer associated with the Lead Market Participant having the lower market share in the capacity auction shall be cleared.

(i) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be the price specified by the System-Wide Capacity Demand Curve for the system-wide capacity entered into the Annual Capacity Auction that maximizes social surplus. In no case, however, shall the Capacity Clearing Price for the Rest-of-Pool Capacity Zone be less than the highest price specified in an offer for capacity that clears the auction, excluding any capacity that, due to its specified price, would not have cleared but for the fact that it is located within an import-constrained Capacity Zone that has a cleared quantity of capacity equal to or less than the truncation point for the zone's Capacity Zone Demand Curve.

(j) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an import-constrained Capacity Zone shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the import-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone; and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the import-constrained Capacity Zone and that clears the auction.

(k) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the export-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Rest-of-Pool Zone; and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the export-constrained Capacity Zone and that clears the auction.

(l) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an export-constrained Capacity Zone that is a nested export-constrained Capacity Zone, shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the export-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Capacity Zone in which the nested Capacity Zone is located; and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the export-constrained Capacity Zone and that clears the auction.

(m) The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for an import-constrained Capacity Zone shall not exceed the Capacity Auction Offer Price Cap. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

(n) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an interface between the New England Control Area and an external Control Area shall be equal to:

(i) if the quantity of capacity over the external interface that clears the auction is equal to the external interface limit for such interface, the highest price specified in a Capacity Offer for capacity that is supplied from a resource offering capacity over such external interface and that clears the auction; or

(ii) if the quantity of capacity over the external interface that clears the auction is less than the external interface limit for such interface, the Capacity Clearing Price for the Capacity Zone associated with the external interface.

III.15.4.2.3. Results of the Annual Capacity Auction.

(a) Annual Capacity Supply Obligations shall be awarded to Capacity Resources in accordance with the results of the Annual Capacity Auction clearing mechanics described in Section III.15.4.2.2. For Intermittent Power Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.15.2) shall be adjusted based on the winter Qualified Capacity as determined pursuant to Section III.15.3.2.2. Additional Capacity Supply Obligations may be awarded in accordance with Section III.15.4.2.4.

(b) The Capacity Clearing Prices in each Capacity Zone modeled in the Annual Capacity Auction shall be the clearing prices determined as a result of the Annual Capacity Auction clearing mechanics described in Section III.15.4.2.2.

III.15.4.2.4. Additional Clearing of Auction in the Event of Cleared Proxy Offers.

If any Proxy Capacity Offer entered into the Annual Capacity Auction clears and receives a Capacity Supply Obligation, the ISO shall conduct an additional run of the auction. This additional run shall use the same methodology described in Section III.15.4.2.2, except that the additional run shall (i) exclude all Proxy Capacity Offers and (ii) enter all other capacity that cleared in the primary run of the Annual Capacity Auction at a price of $0.00/kW-month. The additional run of the auction shall not affect the Capacity Clearing Prices of the primary run of the Annual Capacity Auction pursuant to Section III.15.4.2.2. Capacity (other than capacity still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receives a Capacity Supply Obligation as a result of the primary run of the Annual Capacity Auction shall be paid the Capacity

Clearing Price in the Capacity Zone associated with the capacity during the associated Capacity Commitment Period. Where the additional run of the auction procures additional capacity, that additionally procured capacity shall be paid the price resulting from the additional run in the Capacity Zone associated with that additional capacity during the associated Capacity Commitment Period, and such price shall be equal to or greater than the price resulting from the primary run of the Annual Capacity Auction in that Capacity Zone.

III.15.4.3. Publication of Annual Capacity Auction Results.

As soon as practicable after the Annual Capacity Auction is complete, the ISO shall publish the results of that Annual Capacity Auction publicly on its website, including the set of Capacity Zones modeled in the auction, the Capacity Clearing Prices in each of those Capacity Zones, and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. The published information shall identify Proxy Capacity Offers that cleared, if any, in the primary run of the Annual Capacity Auction.

III.15.5. Monthly Reconfiguration Auctions.

For each Capacity Commitment Period, the ISO shall conduct Monthly Reconfiguration Auctions as described in this Section III.15.5. Monthly Reconfiguration Auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in the Monthly Reconfiguration Auctions. Each reconfiguration auction shall use a static double auction (respecting the interface limits and capacity requirements modeled as specified in Section III.15.5.1) to clear supply offers (i.e., offers to assume a Capacity Supply Obligation) and demand bids (i.e., bids to shed a Capacity Supply Obligation) for each Capacity Zone included in the reconfiguration auction. Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected. Resources that are able to meet the requirements in other Capacity Zones shall be allowed to clear to meet such requirements, subject to the constraints modeled in the auction.

III.15.5.1. Capacity Zones Included in Monthly Reconfiguration Auctions.

Each Monthly Reconfiguration Auction associated with a Capacity Commitment Period shall include each of, and only, the Capacity Zones and external interfaces modeled in the Annual Capacity Auction for that Capacity Commitment Period in accordance with Section III.15.4.2.2.

III.15.5.2. Participation in Monthly Reconfiguration Auctions.

Each supply offer and demand bid in a Monthly Reconfiguration Auction must be associated with a specific resource and must satisfy the requirements of this Section III.15.5.2. All resource types may submit supply offers and demand bids in reconfiguration auctions. In accordance with Section III.A.13.2, supply offers and demand bids submitted for Monthly Reconfiguration Auctions shall not be subject to mitigation by the Internal Market Monitor. Offers composed of separate resources may not participate in reconfiguration auctions. Resources with capacity subject to delayed deactivation pursuant to Sections II.52 and II.53 may not participate in reconfiguration auctions, unless otherwise authorized pursuant to the terms of a cost-of-service agreement of the type described in Section II.54.1. Participation in any reconfiguration auction is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of the offer and bid deadline. The offer and bid deadline for each Monthly Reconfiguration Auction shall be announced by the ISO no later than 10 Business Days prior to that deadline. Upon issuance of the monthly bilateral results for the associated Obligation Month, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that monthly auction, as calculated pursuant to this Section III.15.5.2.

III.15.5.2.1. Supply Offers in Monthly Reconfiguration Auctions.

(a) All supply offers in Monthly Reconfiguration Auctions shall be submitted by the Lead Market Participant, and shall specify the resource, the amount of capacity offered in MW, and the price, denominated in $/kW-month.

(b) A resource may not submit a supply offer for a Monthly Reconfiguration Auction unless a Monthly Qualified Capacity value has been established for the resource for the month associated with the Monthly Reconfiguration Auction pursuant to the qualification processes described in Sections III.15.2 and III.15.3.

(c) The amount of capacity up to which a resource may submit a supply offer in a Monthly Reconfiguration Auction shall be the difference (but in no case less than zero) between (i) the resource's Monthly Qualified Capacity for the month associated with the auction, as determined pursuant to Section III.15.3 during the most recent qualification process for the resource; and (ii) the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for that month.

III.15.5.2.2. Demand Bids in Monthly Reconfiguration Auctions.

(a) All demand bids in Monthly Reconfiguration Auctions shall be submitted by the Lead Market Participant and shall specify the amount of capacity bid in MW and the price, denominated in $/kW-month.

(b) To submit a demand bid in a Monthly Reconfiguration Auction, a resource must have a Capacity Supply Obligation for the month associated with that Monthly Reconfiguration Auction.

(c) Where capacity associated with a Self-Supplied Capacity Resource that cleared in the Annual Capacity Auction for the Capacity Commitment Period is offered in a Monthly Reconfiguration Auction, a resource acquiring a Capacity Supply Obligation in that Monthly Reconfiguration Auction shall not as a result become a Self-Supplied Capacity Resource.

(d) Each demand bid submitted to the ISO for a Monthly Reconfiguration Auction shall be no greater than the amount of the resource's capacity that is already obligated for the month associated with that Monthly Reconfiguration Auction as of the offer and bid deadline for the auction.

III.15.5.3. Clearing Offers and Bids in Monthly Reconfiguration Auctions.

All supply offers and demand bids are rationable and may be cleared in whole or in part in Monthly Reconfiguration Auctions.

III.15.5.4. Conduct of Monthly Reconfiguration Auctions.

Prior to each month in the Capacity Commitment Period, the ISO shall conduct a Monthly Reconfiguration Auction for whole-month capacity commitments during that month. For each Monthly Reconfiguration Auction, the ISO shall employ an optimization algorithm that is designed to maximize social surplus in order to clear the supply offers against demand bids submitted for the auction. The truncation points for import-constrained Capacity Zones and export-constrained Capacity Zones specified in Section III.15.1.1.2 and Section III.15.1.1.3 and external interface limits established pursuant to Section III.12 shall be modeled as constraints in the auction. The System-Wide Capacity Demand Curve is not modeled in Monthly Reconfiguration Auctions.

III.15.5.5. Adjustment to Capacity Supply Obligations.

For each supply offer that clears in a Monthly Reconfiguration Auction, the resource's Capacity Supply Obligation for the month associated with the auction shall be increased by the amount of capacity that clears. For each demand bid that clears in a Monthly Reconfiguration Auction, the resource's Capacity Supply Obligation for the month associated with the auction shall be decreased by the amount of capacity that clears.

III.15.6. Bilateral Capacity Contracts.

Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals and Capacity Load Obligation Bilaterals in accordance with this Section III.15.6, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation. To the extent necessary for the ISO's review and approval of any of the bilateral contracts described in this Section III.15.6, the ISO shall apply the Capacity Zones and external interfaces modeled as inputs and constraints in the Annual Capacity Auction for the applicable Capacity Commitment Period, as described in Section III.15.4.2.2. Resources with capacity subject to delayed deactivation pursuant to Sections II.52 and II.53 may not participate in Capacity Supply Obligation Bilaterals, unless otherwise authorized pursuant to the terms of a cost-of-service agreement of the type described in Section II.54.1.

III.15.6.1. Capacity Supply Obligation Bilaterals.

A Capacity Transferring Resource having a Capacity Supply Obligation and seeking to shed that obligation may enter into a Capacity Supply Obligation Bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part, to a Capacity Acquiring Resource, or portion thereof, for a whole-month period during the Capacity Commitment Period, as described in this Section III.15.6.1.

III.15.6.1.1. Terms of and Participation in Capacity Supply Obligation Bilaterals.

(a) Capacity Supply Obligation Bilaterals are available for monthly periods, and a Capacity Supply Obligation Bilateral must be coterminous with a calendar month.

(b) The qualification of Capacity Acquiring Resources for participation in Capacity Supply Obligation Bilaterals is determined in the same manner as the qualification of resources submitting supply offers for Monthly Reconfiguration Auctions as specified in Section III.15.5.2.1(b). A resource that does not have a Monthly Qualified Capacity value established for the month covered by the Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that month.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the monthly Capacity Supply Obligation of the Capacity Transferring Resource. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the amount of unobligated Monthly Qualified Capacity of the Capacity Acquiring Resource for the month covered by the Capacity Supply Obligation Bilateral. For the purpose of this subsection (c), unobligated Monthly Qualified Capacity refers to the Monthly Qualified Capacity that was

determined pursuant to Section III.15.3 in the most recent qualification process for the resource prior to the submission of the Capacity Supply Obligation Bilateral to the ISO and that is not subject to a Capacity Supply Obligation.

(d) A resource, or a portion thereof, that has been designated as a Self-Supplied Capacity Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied Capacity Resource as a result of the transaction.

(e) Capacity Supply Obligation Bilaterals are allowed between a Capacity Transferring Resource and a Capacity Acquiring Resource that are located within different Capacity Zones and across external interfaces modeled as part of the Annual Capacity Auction for the Capacity Commitment Period of the relevant monthly period, subject to the transmission interface limits between Capacity Zones and external interface limits, as described in Section III.15.6.1.4(b).

(f) Participation in any Capacity Supply Obligation Bilateral is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of submission to the ISO.

III.15.6.1.2. Timing of Submission and Prior Notification to the ISO.

The Lead Market Participant for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Capacity Supply Obligation Bilaterals in the Capacity Auction Calendar. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than the end of the relevant submittal window.

III.15.6.1.3. Contents of Submission to the ISO.

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, denominated in $/kW-

month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of $0.00/kW-month.

III.15.6.1.4. ISO Review.

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral and shall reject the Capacity Supply Obligation Bilateral if any of the submission and participation requirements described in this Section III.15.6.1 are not met. For a Capacity Supply Obligation Bilateral submitted before the relevant submittal window opens, this review shall occur once the submittal window opens. For a Capacity Supply Obligation Bilateral submitted after the submittal window opens, this review shall occur upon submission.

(b) After the close of the submittal window, the ISO shall conduct a review to determine the deliverability of the submitted Capacity Supply Obligation Bilaterals. In its review, the ISO shall model as constraints the truncation points for import-constrained Capacity Zones and export-constrained Capacity Zones specified in Sections III.15.1.1.2 and III.15.1.1.3 and external interface limits established pursuant to Section III.12 for the applicable Capacity Commitment Period. The ISO shall reject Capacity Supply Obligation Bilaterals that are not fully deliverable up to their specific MW values without violating transmission transfer limits between Capacity Zones or external transfer limits. Transactions will only be accepted or rejected in their entirety. The ISO shall approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected, the Lead Market Participant for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the basis for such rejection.

(c) Each Capacity Supply Obligation Bilateral shall be subject to a financial assurance review by the ISO. If the Capacity Transferring Resource and the Capacity Acquiring Resource are not both in compliance with all applicable provisions of the ISO New England Financial Assurance Policy, including those regarding Capacity Supply Obligation Bilaterals, the ISO shall reject the Capacity Supply Obligation Bilateral.

III.15.6.1.5. Approval.

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource for the month covered by the Capacity Supply Obligation Bilateral shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply

Obligation of the Capacity Acquiring Resource for the month covered by the Capacity Supply Obligation Bilateral shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

III.15.6.2. Capacity Load Obligations Bilaterals.

A Capacity Load Obligation Transferring Participant seeking to shed its Capacity Load Obligation may enter into a Capacity Load Obligation Bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone to a Capacity Load Obligation Acquiring Participant seeking to acquire a Capacity Load Obligation, as described in this Section III.15.6.2.

III.15.6.2.1. Terms of and Participation in Capacity Load Obligation Bilaterals.

A Capacity Load Obligation Bilateral must be in whole calendar month increments, may not exceed one year in duration, and must begin and end within the same Capacity Commitment Period. A Capacity Load Obligation Transferring Participant will be permitted to transfer, and a Capacity Load Obligation Acquiring Participant will be permitted to acquire, a Capacity Load Obligation if after entering into a Capacity Load Obligation Bilateral and submitting related information to the ISO within the specified submittal time period, the ISO approves such Capacity Load Obligation Bilateral.

III.15.6.2.2. Timing of Submission to the ISO.

Either the Capacity Load Obligation Transferring Participant or the Capacity Load Obligation Acquiring Participant may submit a Capacity Load Obligation Bilateral to the ISO. All Capacity Load Obligation Bilaterals must be submitted to the ISO in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial daily settlements of payments and charges associated with the Annual Capacity Market for the first month of the term of the Capacity Load Obligation Bilateral, a Capacity Load Obligation Bilateral must be submitted to the ISO no later than 12:00 p.m. on the first Business Day of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

III.15.6.2.3. Contents of Submission to the ISO.

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following: (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant

and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

III.15.6.2.4. ISO Review.

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section III.15.6.2 are not met.

III.15.6.2.5. Approval.

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral for the period covered by the bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral for the period covered by the bilateral.

III.15.7. Obligations of Capacity Suppliers.

Resources assuming a Capacity Supply Obligation through an Annual Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a Monthly Reconfiguration Auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.15.7 for each Capacity Commitment Period.

III.15.7.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through an Annual Capacity Auction, Monthly Reconfiguration Auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.15.7.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.15.7.1.1. Generating Capacity Resources with Capacity Supply Obligations.

III.15.7.1.1.1. Energy Market Offer Requirements.

(a) A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically

available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:

(i) the sum of the Generating Capacity Resource's Notification Time plus Start-Up Time plus Minimum Run Time plus Minimum Down Time is less than or equal to 72 hours; or

(ii) if the Generating Capacity Resource cannot meet the offer requirements in Section III.15.7.1.1.1(a)(i) due to physical design limits, then the resource shall be offered into the Day-Ahead Energy Market at a MW amount equal to or greater than its Economic Minimum Limit at a price of zero or shall be self-scheduled in the Day-Ahead Energy Market at a MW amount equal to or greater than the resource's Economic Minimum Limit.

(b) Notwithstanding the foregoing, if the Generating Capacity Resource is a Settlement Only Resource, it may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.1.1.2. Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the known capability of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.19.

III.15.7.1.1.3. [Reserved.]

III.15.7.1.1.4. [Reserved.]

III.15.7.1.1.5. Additional Requirements for Generating Capacity Resources.

Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1 and the requirement to provide to the ISO, upon request and as soon as practicable, confirmation of gas volume schedules sufficient to deliver the energy scheduled for each Generating Capacity Resource using natural gas; and

(c) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures (except that Settlement Only Resources are not subject to outage requirements), provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.15.7.1.2. Import Capacity Resources with Capacity Supply Obligations.

III.15.7.1.2.1. Energy Market Offer Requirements.

A Market Participant with an Import Capacity Resource must offer one or more External Transactions to import energy in the Day-Ahead Energy Market and Real-Time Energy Market for every hour of each Operating Day at the same external interface that, in total, equal the resource's Capacity Supply Obligation, except that:

(a) the offer requirement does not apply to any hour in which any External Resource associated with an Import Capacity Resource is on an outage;
(b) the Day-Ahead Energy Market offer requirement does not apply to any hour in which the import transfer capability of the external interface is 0 MW, and;
(c) the Real-Time Energy Market offer requirement does not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which Coordinated Transaction Scheduling is implemented.

Each External Transaction submitted in the Day-Ahead Energy Market must reference the associated Import Capacity Resource.

Each External Transaction submitted in the Real-Time Energy Market in accordance with Section III.1.10.7 must reference the associated Import Capacity Resource.

III.15.7.1.2.2. Additional Requirements for Import Capacity Resources.

A Market Participant with an Import Capacity Resource that is associated with an External Resource must:

(a) comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the External Resource's native Control Area, and;

(b) notify the ISO of all outages impacting the Capacity Supply Obligation of the Import Capacity Resource in accordance with the outage notification requirements in ISO New England Operating Procedure No. 5.

III.15.7.1.3. Intermittent Power Resources with Capacity Supply Obligations.

III.15.7.1.3.1. Energy Market Offer Requirements.

(a) Market Participants with Intermittent Power Resources that are Dispatchable Resources and have a Capacity Supply Obligation are required to submit offers in the Day-Ahead Energy Market consistent with the Market Participant's expectation of the output of the resource in Real-Time. Market Participants with non-dispatchable Intermittent Power Resources with a Capacity Supply Obligation may submit, but are not required to submit, offers into the Day-Ahead Energy Market. Market Participants are required to submit offers for Intermittent Power Resources with a Capacity Supply Obligation for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day-Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

(b) Notwithstanding the foregoing, an Intermittent Power Resource that is a Settlement Only Resource may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.1.3.2. [Reserved.]

III.15.7.1.3.3. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources with Capacity Supply Obligations are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals (except that Intermittent Power Resources that are Settlement Only Resources need not comply with outage requirements).

III.15.7.1.4. [Reserved.]

III.15.7.1.5. Demand Capacity Resources with Capacity Supply Obligations.

III.15.7.1.5.1. Energy Market Offer Requirements.

(a) A Market Participant with an Active Demand Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers for its Demand Response Resources into the Day-Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.15.7.1.5.1; for purposes of the following comparisons, the portion of Demand Reduction Offers not associated with Net Supply shall be increased by average avoided peak transmission and distribution losses. The sum of the Demand Reduction Offers must be equal to or greater than the Active Demand Capacity Resource's Capacity Supply Obligation whenever the Demand Response Resources are physically available. If the Demand Response Resources are physically available at a level less than the Active Demand Capacity Resource's Capacity Supply Obligation, the sum of the Demand Reduction Offers will equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each Demand Reduction Offer from a Demand Response Resource made into the Day-Ahead Energy Market shall also meet the following requirement:

(i) the sum of the Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time plus Minimum Reduction Time plus Minimum Time Between Reductions is less than or equal to 72 hours.

(b) Seasonal Peak Demand Capacity Resources and On-Peak Demand Capacity Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.1.5.2. Requirement that Offers Reflect Accurate Demand Response Resource Operating Characteristics.

For each day, Demand Reduction Offers submitted into the Day-Ahead Energy Market and Real-Time Energy Market for a Demand Response Resource associated with an Active Demand Capacity Resource must reflect the then-known operating characteristics of the resource. Consistent with Section III.1.10.9(d), Demand Response Resources must re-declare to the ISO any changes to offer parameters that occur in real time to reflect the operating characteristics of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.19.

III.15.7.1.5.3. Additional Requirements for Demand Capacity Resources.

(a) A Market Participant may not associate an Asset with a non-commercial Demand Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Demand Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) An Energy Efficiency measure may be added to an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource (other than one consisting of Load Management or Distributed Generation) until two years after the start of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation; provided, however, that a resource that qualified for a Forward Capacity Auction associated with a Capacity Commitment Period beginning on or before June 1, 2024 may install Energy Efficiency measures until May 31, 2027. Once an Energy Efficiency measure has been associated with an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, the measure may not be transferred to a different resource.

(c) For purposes of confirming Capacity Market Commercial Operation as described in Section III.15.2.6, the ISO shall use a summer Seasonal DR Audit value or summer Passive DR Audit value to verify the capacity rating of a Demand Capacity Resource with summer Qualified Capacity. A winter Seasonal DR Audit value or winter Passive DR Audit value may only be used to verify the winter commercial capacity of a Demand Capacity Resource. The summer and winter commercial capacity of a Demand Capacity Resource consisting of Energy Efficiency measures may be verified in any month of the year.

(d) For Active Demand Capacity Resources, a summer Seasonal DR Audit value shall be established for use from April 1 through November 30 and a winter Seasonal DR Audit value shall be established for use from December 1 through March 31. The summer or winter Seasonal DR Audit value of an Active Demand Capacity Resource is equal to the sum of the like-season Seasonal DR Audit values of its constituent Demand Response Resources as determined pursuant to Section III.1.5.1.3.1. The Seasonal DR Audit value of an Active Demand Capacity Resource shall automatically update whenever a new Seasonal DR Audit value is approved for a constituent Demand Response Resource or with changes to the makeup of the constituent Demand Response Resources.

(e) On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources shall in addition: (i) comply with the ISO's measurement and verification requirements pursuant to Section III.15.2.1.1.2.1. and the ISO New England Manuals; and (ii) comply with the auditing and rating requirements as detailed in Sections III.15.7.1.5.4 and III.15.7.1.5.5 and the ISO New England Manuals.

(f) Active Demand Capacity Resources shall in addition: (i) comply with the measurement and verification requirements and the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures; and (ii) comply with the auditing and rating requirements as detailed in Section III.15.7.1.5.5 and the ISO New England Manuals.

III.15.7.1.5.4. On-Peak Demand Capacity Resource and Seasonal Peak Demand Capacity Resource Auditing Requirements.

(a) A summer Passive DR Audit value and a winter Passive DR Audit value must be established for each On-Peak Demand Capacity Resource and Seasonal Peak Demand Capacity Resource in every Capacity Commitment Period during which the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource has an annual or monthly Capacity Supply Obligation.

(b) Summer Passive DR Audit values shall be determined based on data for one or more months of the summer Passive DR Auditing Period (June through August). Winter Passive DR Audit values shall be

determined based on data for one or more months of the winter Passive DR Auditing Period (December through January).

(c) Passive DR Audit values shall be made available to the Market Participant within 20 Business Days following the end of the period for which the audit value is determined by the ISO.

(d) The audit value of an On-Peak Demand Capacity Resource shall be determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the On-Peak Demand Capacity Resource during the Demand Resource On-Peak Hours.

(e) The audit value of a Seasonal Peak Demand Capacity Resource shall be determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the Seasonal Peak Demand Capacity Resource during the Demand Resource Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in a month during the Passive DR Auditing Period, performance during Demand Resource On-Peak Hours in that month may be used.

(f) Passive DR Audit values shall become effective one calendar day after being made available to the Market Participant and remain valid until the earlier of: (i) the next like-season Passive DR Audit value becomes effective or (ii) the end of the following Capability Demonstration Year.

(g) For On-Peak Demand Capacity Resources consisting of Energy Efficiency measures and Seasonal Peak Demand Capacity Resources consisting of Energy Efficiency measures, the ISO shall calculate a summer Passive DR Audit value and a winter Passive DR Audit value in each month of the year. For all other On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources, a Market Participant may request that a summer or winter Passive DR Audit value be determined based on data for, respectively, a summer or winter month outside of the Passive DR Auditing Periods. Such an audit shall not satisfy the Passive DR Audit requirement.

III.15.7.1.5.5. Additional Demand Capacity Resource Audits.

The ISO may perform one or both of the following additional audits for a Demand Capacity Resource to establish or verify the capability of the Demand Capacity Resource and its underlying assets and measures.

(a) Level 1 Audit: the ISO shall establish the audit results by conducting a review of records of the Assets and measures to verify that the reported Assets and measures have been installed and are operational. The audit shall include, but is not limited to, reviewing project or program databases, invoices, installation reports, work orders, and field inspection reports. In addition, the audit may involve reviewing any independent inspections or evaluations conducted as part of program implementation and program evaluation.

(b) Level 2 Audit: the ISO shall establish the audit results by initiating or conducting an on-site field audit to verify the installation and performance of the Assets and measures. Such an audit may include a random or select sample of facilities and measures.

A level 1 audit is not required to precede a level 2 audit. If the results of the audit indicate that the demand reduction capability of the Demand Capacity Resource is less than or greater than its most recent like-season Passive DR Audit value or Seasonal DR Audit value, then the Demand Capacity Resource's audit value shall be adjusted accordingly.

III.15.7.1.6. DNE Dispatchable Generator.

III.15.7.1.6.1. Energy Market Offer Requirements.

DNE Dispatchable Generators with a Capacity Supply Obligation must submit offers into the Day-Ahead Energy Market for the full amount of the resource's expected hourly physical capability as determined by the Market Participant. Market Participants with DNE Dispatchable Generators having a Capacity Supply Obligation must submit offers for the Real-Time Energy Market consistent with the characteristics of the resource. For purposes of calculating Real-Time NCPC Charges, DNE Dispatchable Generators shall have a generation deviation of zero.

III.15.7.1.7. Distributed Energy Capacity Resources with Capacity Supply Obligations.

III.15.7.1.7.1. Energy Market Offer Requirements.

(a) A Market Participant with a Distributed Energy Capacity Resource having a Capacity Supply Obligation shall submit offers for its Distributed Energy Resource Aggregations into the Day-Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.15.7.1.7.1; for purposes of the following comparisons, the portion of any Demand Reductions Offers or Baseline Deviation Offers not associated with Net Supply shall be increased by average avoided peak

transmission and distribution losses. The sum of the offers must be equal to or greater than the Distributed Energy Capacity Resource's Capacity Supply Obligation whenever the Distributed Energy Resource Aggregations are physically available. If the Distributed Energy Resource Aggregations are physically available at a level less than the Distributed Energy Capacity Resource's Capacity Supply Obligation, the sum of the offers must equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each offer from a Distributed Energy Resource Aggregation made into the Day- Ahead Energy Market shall also meet the following requirement:

(i) the sum of the resource's notification time plus start-up time plus Minimum Run Time (or Minimum Deviation Time or Minimum Reduction Time) plus Minimum Down Time (or Minimum Time Between Deviations or Minimum Time Between Reductions) is less than or equal to 72 hours.

(b) Notwithstanding the foregoing, if the Distributed Energy Capacity Resource comprises Settlement Only Distributed Energy Resource Aggregations, it is not obligated to submit Supply Offers into the Day-Ahead Energy Market and may not submit Supply Offers into the Real-Time Energy Market.

III.15.7.1.7.2. Requirement that Offers Reflect Accurate Distributed Energy Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the then-known capability of the resource.

III.15.7.1.7.3. Additional Requirements for Distributed Energy Capacity Resources.

Distributed Energy Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) A Market Participant may not associate an Asset with a non-commercial Distributed Energy Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Distributed Energy Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) Distributed Energy Capacity Resources shall comply with the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

(c) Distributed Energy Capacity Resources shall comply with the auditing and rating requirements as detailed in this Market Rule 1 and the ISO New England Manuals.

(d) For Distributed Energy Capacity Resources, the Seasonal DECR Audit Value shall be established pursuant to Section III.1.7.13.

III.15.7.2. Resources without a Capacity Supply Obligation.

A resource that does not have any Capacity Supply Obligation shall comply with the requirements in this Section III.15.7.2 and shall not be subject to the requirements set forth in Section III.15.7.1 during the Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.15.7.2.1. Generating Capacity Resources without a Capacity Supply Obligation.

III.15.7.2.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. A Generating Capacity Resource that is a Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.2.1.1.1. Day-Ahead Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Day-Ahead Energy Market. If any portion of the offered energy clears in the Day-Ahead Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the operating day,

including the obligation to follow ISO Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.1.1.2. Real-Time Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Real-Time Energy Market. If any portion of the offered energy clears in the Real-Time Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Real-Time Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow ISO Dispatch Instructions. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.1.2. Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation.

Generating Capacity Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with the auditing and rating requirements as detailed in the ISO New England Manuals;

(b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Generating Capacity Resources having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.15.7.2.2. Distributed Energy Capacity Resources without a Capacity Supply Obligation.

III.15.7.2.2.1. Energy Market Offer Requirements.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation is not required to submit offers for the resource into the Day-Ahead Energy Market or Real-Time Energy Market. A Market Participant

with a Settlement Only Distributed Energy Resource Aggregation is not permitted to submit an offer for that resource into the Real-Time Energy Market.

III.15.7.2.2.2. Day-Ahead Energy Market Participation.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation may submit an offer into the Day- Ahead Energy Market. If any portion of the offer clears in the Day-Ahead Energy Market, the entire offer, up to the maximum capability offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market so long as it is not a Settlement Only Distributed Energy Resource Aggregation.

III.15.7.2.2.3. Real-Time Energy Market Participation.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation, that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit an offer in the Real-Time Energy Market so long as the resource is not a Settlement Only Distributed Energy Resource Aggregation, and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.2.4. Additional Requirements for Distributed Energy Capacity Resources Having No Capacity Supply Obligation.

Distributed Energy Capacity Resources without a Capacity Supply Obligation shall comply with the requirements in Section III.15.7.1.7.3.

III.15.7.2.3. Intermittent Power Resources without a Capacity Supply Obligation.

III.15.7.2.3.1. Energy Market Offer Requirements.

An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. An Intermittent Power Resource that is a Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.2.3.2. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals; and

(b) Operating Data collection requirements as detailed in the ISO New England Manuals.

III.15.7.2.4. [Reserved.]

III.15.7.2.5. Demand Capacity Resources without a Capacity Supply Obligation.

III.15.7.2.5.1. Energy Market Offer Requirements.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation is not required to offer Demand Reduction Offers for the Demand Response Resource into the Day-Ahead Energy Market or Real-Time Energy Market.

Seasonal Peak Demand Capacity Resources and On-Peak Demand Capacity Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.2.5.1.1. Day-Ahead Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation may submit a Demand Reduction Offer into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer, up to the Maximum Reduction offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.5.1.2. Real-Time Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit a Demand Reduction Offer in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.5.2. Additional Requirements for Demand Capacity Resources Having No Capacity Supply Obligation.

Demand Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with Section III.15.7.1.5.3(a) and (b) and with the auditing and rating requirements described in Section III.15.7.1.5.5 and the ISO New England Manuals;

(b) for Active Demand Capacity Resources, complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) for Active Demand Capacity Resources, complying with outage requirements as detailed in the ISO New England Operating Procedures and ISO New England Manuals. Active Demand Capacity Resources having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.15.7.3. Exporting Resources.

A resource that is exporting capacity not subject to a Capacity Supply Obligation to an external Control Area shall comply with this Section III.15.7.3 and the ISO New England Manuals. Intermittent Power Resources and Demand Capacity Resources are not permitted to back a capacity export to an external Control Area. The portion of a resource without a Capacity Supply Obligation that will be used in Real-Time to support an External Transaction sale must comply with the energy market offer requirements of Section III.1.10.7 and Section III.1.10.7.A, as applicable.

III.15.7.4. ISO Requests for Energy.

The ISO may request that an Active Demand Capacity Resource, a Generating Capacity Resource, or a Distributed Energy Capacity Resource having capacity that is not subject to a Capacity Supply Obligation provide energy for reliability purposes in the Real-Time Energy Market, but such resource shall not be obligated under this Section III.15 by such a request to provide energy from that capacity. If such resource does provide energy from that capacity, the resource shall be paid based on its most recent offer and is eligible for NCPC.

III.15.7.4.1. Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.15.7.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.

III.15.8. Capacity Payments and Charges.

Revenue in the Annual Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.15.8.1 and Capacity Performance Payments as described in Section III.15.8.2, adjusted as described in Section III.15.8.3 and Section III.15.8.4. Market Participants with a Capacity Load Obligation shall be subject to charges as described in Section III.15.8.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.15 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.15.8.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.15.8.1.1.

III.15.8.1.1. Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in an Annual Capacity Auction, except for the portion of resources designated as Self-Supplied Capacity Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.15.8.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(a) **Annual Capacity Auction**. For a resource whose offer has cleared in an Annual Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the

Forward Capacity Auction in which the offer cleared, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only, and subject to the limitations set forth in Section III.15.2.1.3.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in a Monthly Reconfiguration Auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and the price associated with the Capacity Supply Obligation Bilateral.

III.15.8.1.2 Export Capacity

If there are any unobligated Export Offer Segments from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Annual Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows.

Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x [Cleared MWs of Export Offer Segment]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x [Cleared MWs of Export Offer Segment]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.15.8.5.2.

III.15.8.2. Capacity Performance Payments.

III.15.8.2.1. Definition of Capacity Scarcity Condition.

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

III.15.8.2.2. Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.15.8.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided

for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures, the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.15.8.2.2(c), for any On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.15.8.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(ii) A Demand Response Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource's Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource's Actual Capacity Provided shall not be less than zero.

(iii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

(e) A Distributed Energy Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Metered Quantity for Settlement and Reserve Quantity for Settlement of all the components of its constituent Distributed Energy Resource Aggregations; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Based on the Real-Time operational coordination, the resource must follow any distribution system limitation and update its physical parameters accordingly. The Actual Capacity Provided cannot be less than zero.

(i) The Real-Time demand reduction of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource or Demand Response Distributed Energy Resource Aggregation does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response

Baseline of the Demand Response Asset or Distributed Energy Resource associated with the Demand Response Distributed Energy Resource Aggregation; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.15.8.2.3. Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

provided, however, that the Capacity Balancing Ratio shall not exceed a value of 1.0.

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.15.8.2.A.2 in the New England Control Area during the interval.

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.15.8.2.A.2 in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.15.8.2.A.2 in the Capacity Zone during the interval.

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.15.8.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

III.15.8.2.4. Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Capacity Resource or a Seasonal Peak Demand Capacity Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.15.8.2.5. Capacity Performance Payment Rate.

The Capacity Performance Payment Rate shall be $3500/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.15.8.2.6. Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.15.8.2.A System-Backed Export Charges.

III.15.8.2.A.1 System-Backed Exports.

A System-Backed Export is an External Transaction submitted in accordance with Section III.1.10.7 or Section III.1.10.7.A to export internal energy out of the New England Control Area by a Market Participant in the Real-Time Energy Market: (1) that is not associated with a generator; or (2) for External Transactions associated with a generator, for which the megawatt amount of the External Transaction sale(s) associated with the generator is greater than the sum of the resource's energy output plus the resource's Reserve Quantity For Settlement.

III.15.8.2.A.2 Calculation of System-Backed Export Charges.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a System-Backed Export Charge: (1) for External Transactions associated with a generator, for each resource that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval; and (2) for External Transactions not associated with a generator, for each Market Participant that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval. For each five-minute interval, the System-Backed Export Charge shall be equal to the net System-Backed Export value, calculated in accordance with the formulas set forth below, multiplied by the Capacity Performance Payment Rate, as defined in Section III.15.8.2.5.

For External Transactions associated with a generator,

net System-Backed Export value = the lesser of (the energy output of the generator in the interval + the Reserve Quantity for Settlement of the generator in the interval – the hourly integrated delivered MW for the External Transaction sale(s) associated with the generator) or 0

System-Backed Export Charge = net System-Backed Export value × Capacity Performance Payment Rate

For External Transactions not associated with a generator,

net System-Backed Export value = the lesser of (the hourly integrated delivered MW for the External Transaction purchase(s) of the Market Participant – the hourly integrated delivered MW for the External Transaction sale(s) of the Market Participant) or 0

System-Backed Export Charge = net System-Backed Export value × Capacity Performance Payment Rate

Unless otherwise expressly stated, a System-Backed Export Charge shall not be treated as a Capacity Performance Payment under the Tariff.

III.15.8.3. Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.15.8.3.1 and Section III.15.8.3.2 below.

III.15.8.3.1. Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month shall be limited to an amount equal to the product of the applicable Capacity Auction Offer Price Cap multiplied by the resource's Capacity Supply Obligation for the Obligation Month.

III.15.8.3.2. Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [3 months x (ACAcp – ACAsp) – (12 months x ACAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

ACAcp = the Capacity Clearing Price for the relevant Annual Capacity Auction.

ACAsp = the Annual Capacity Auction Offer Price Cap for the relevant Annual Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.15.8.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month shall be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.15.8.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.15.8.3.2(b).

III.15.8.4. Allocation of Deficient or Excess Capacity Performance Payments and System-Backed Export Charges.

For Capacity Scarcity Conditions as described in Section III.15.8.2.1, the ISO shall allocate deficient or excess Capacity Performance Payments and System-Backed Export Charges as described in subsections (a), (b), and (c) below.

(a) If the sum of all Capacity Performance Payments and System-Backed Export Charges to all resources subject to a Capacity Scarcity Condition in an Obligation Month is positive, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.15.8.3, the deficiency shall be charged to resources in proportion to the sum of each such resource's positive Capacity Performance Score for the Obligation Month.

(b) If the sum of all Capacity Performance Payments and System-Backed Export Charges to all resources subject to a Capacity Scarcity Condition in an Obligation Month is negative, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.15.8.3, the excess shall be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.15.8.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.15.8.3, and the remaining excess shall be further allocated to other resources in the same manner as described in this Section III.15.8.4(b).

(c) If a deficiency of Capacity Performance Payments exists due to one or more resources reaching the stop-loss limit described in Section III.15.8.3, the deficiency shall be charged to all resources subject to a Capacity Scarcity Condition in an Obligation Month that have not reached their stop-loss limit (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. If the charge described in Section III.15.8.4(a) or the charge described in this Section III.15.8.4(c) causes a resource to reach the stop-loss limit described in Section III.15.8.3, then the stop-loss limit described in Section III.15.8.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.15.8.4(c).

III.15.8.5. Charges to Market Participants with Capacity Load Obligations.

III.15.8.5.1. Calculation of Capacity Charges.

For purposes of this Section III.15.8.5.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in rate component (b) of Sections III.15.8.5.1.1 through III.15.8.5.1.8 shall be divided by the number of days in the month to derive a daily settlement value.

III.15.8.5.1.1. Annual Capacity Auction Charge.

The ACA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone ACA Costs divided by Zonal Capacity Obligation.

Where:

Capacity Zone ACA Costs, for each Capacity Zone, are the Total ACA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total ACA Costs are the sum of, for all Capacity Zones, Capacity Supply Obligations in each zone (the total obligation awarded to resources in the Annual Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.15.8.5.1.5) multiplied by the applicable clearing price from the auction in which the obligation was awarded to the resource.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.15.8.5.1.2. Monthly Reconfiguration Auction Charge.

The monthly reconfiguration auction charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total Monthly Reconfiguration Auction Costs divided by Total Zonal Capacity Obligation.

Where:

Total Monthly Reconfiguration Auction Costs are the sum of, for all Capacity Zones, the product of Capacity Supply Obligations acquired through the Monthly Reconfiguration Auction in each zone and the applicable Monthly Reconfiguration Auction clearing price, minus the sum of, for all Capacity Zones, any Capacity Supply Obligations shed through the Monthly Reconfiguration Auction in each zone and the applicable Monthly Reconfiguration Auction clearing price.

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.15.8.5.1.3. HQICC Capacity Charge.

The HQICC capacity charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total HQICC Credits divided by Total Capacity Load Obligation.

Where:

Total HQICC credits are the product of HQICCs multiplied by the sum of the values calculated in Sections III.15.8.5.1.1(b), III.15.8.5.1.2(b), III.15.8.5.1.5(b), III.15.8.5.1.6(b), III.15.8.5.1.7(b), and III.15.8.5.1.8(b) in the Capacity Zone in which the HQ Phase I/II external node is located.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.15.8.5.1.4. Self-Supply Adjustment.

The self-supply adjustment is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) the Self-Supply Variance divided by Total Capacity Load Obligation.

Where:

Self-Supply Variance is the difference between foregone capacity payments and avoided capacity charges associated with designated self-supply quantities.

Foregone capacity payments to Self-Supplied Capacity Resources are the sum, for all Capacity Zones, of the product of the zonal Capacity Supply Obligation designated as self-supply, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Avoided capacity charges are the sum, for all Capacity Zones, of the product of any designated self-supply quantities multiplied by the sum of the values calculated in Sections III.15.8.5.1.1.(b), III.15.8.5.1.2(b), III.15.8.5.1.5(b), III.15.8.5.1.6(b), III.15.8.5.1.7(b) and III.15.8.5.1.8(b) in the Capacity Zone associated with the designated self-supply quantity.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.15.8.5.1.5. Intermittent Power Resource Capacity Adjustment.

The Intermittent Power Resource capacity adjustment in a winter season for the Obligation Months from October through May is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) the Intermittent Power Resource Seasonal Variance divided by Total Zonal Capacity Obligation.

Where:

Intermittent Power Resource Seasonal Variance is the difference between the ACA payments for Intermittent Power Resources in the Obligation Month and the base ACA payments for Intermittent Power Resources.

ACA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to Intermittent Power Resources in the Annual Capacity Auction process for the Obligation Month pursuant to Section III.15.4.2.3, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Base ACA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Annual Qualified Capacity procured from Intermittent Power Resources in the Annual Capacity Auction process, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Total Zonal Capacity Obligation is the total Zonal Capacity Obligation in all Capacity Zones.

III.15.8.5.1.6. CTR Transmission Upgrade Charge.

The CTR transmission upgrade charge is: (a) the Capacity Load Obligation in the Capacity Zones to which the applicable interface limits the transfer of capacity, multiplied by (b) Zonal CTR Transmission Upgrade Cost divided by Zonal Capacity Obligation.

Where:

Zonal CTR Transmission Upgrade Cost for each Capacity Zone to which the interface limits the transfer of capacity is the amount calculated pursuant to Section III.15.8.5.4.1(f), multiplied by the Zonal Capacity Obligation and divided by the sum of the Zonal Capacity Obligation for all Capacity Zones to which the interface limits the transfer of capacity.

III.15.8.5.1.7. CTR Pool-Planned Unit Charge.

The CTR Pool-Planned Unit charge is: (a) the total Capacity Load Obligation in all Capacity Zones less the amount of any CTRs specifically allocated pursuant to Section III.15.8.5.4.2, multiplied by (b) CTR Pool-Planned Unit Cost divided by Total Zonal Capacity Obligation less the amount of any CTRs specifically allocated pursuant to Section III.15.8.5.4.2.

Where:

The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.15.8.5.4.2(b).

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.15.8.5.1.8. Multi-Year Rate Election Adjustment.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where:

Zonal Multi-Year Rate Election Costs is the sum, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that were terminated pursuant to Section III.13.3.4A or Section III.15.A.2.1, or withdrawn pursuant to Section III.15.A.2.3), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, multiplied by the Zonal Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation and divided by the Total Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning prior to June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where:

> Zonal Multi-Year Rate Election Costs is the sum in each Capacity Zone, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that were terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period.

III.15.8.5.2. Calculation of Capacity Load Obligation and Zonal Capacity Obligation.

The ISO shall assign each Market Participant a share of the Zonal Capacity Obligation prior to the commencement of each Obligation Month for each Capacity Zone established in the Annual Capacity Auction pursuant to Section III.12.4. The Zonal Capacity Obligation of a Capacity Zone that contains a nested Capacity Zone shall exclude the Zonal Capacity Obligation of the nested Capacity Zone.

The Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year one year prior to the start of the Capacity Commitment Period to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year one year prior to the start of the Capacity Commitment Period.

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with the receipt of electricity from the grid by Storage DARDs for later injection of electricity back to the grid; when all load of a Distributed Energy Resource Aggregation participating as a Storage DARD is load associated with the receipt of electricity from the grid for later injection of electricity back to the grid; Station service load that is modeled as a discrete Load Asset and

the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as a discrete Load Asset and is exclusively related to an Alternative Technology Regulation Resource following AGC Dispatch Instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A Market Participant's share of Zonal Capacity Obligation for each day of the month and each Capacity Zone shall equal the product of: (i) the Capacity Zone's Zonal Capacity Obligation as calculated above and (ii) the ratio of the sum of the load serving entity's daily Coincident Peak Contributions, to the sum of all load serving entities' daily Coincident Peak Contributions in that Capacity Zone.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each day of the month and each Capacity Zone, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied Capacity Resource designations. A Capacity Load Obligation can be a positive or negative value.

A Market Participant's share of Zonal Capacity Obligation will not be reconstituted to include the demand reduction of a Demand Capacity Resource, Demand Response Resource, or a Demand Response Distributed Energy Resource Aggregation.

III.15.8.5.2.1. Charges Associated with Dispatchable Asset Related Demands.
Dispatchable Asset Related Demand resources will not receive Annual Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.15.8.5.3. Excess Revenues.
Any payment associated with a Capacity Supply Obligation Bilateral that was to accrue to a Capacity Acquiring Resource for a Capacity Supply Obligation that is terminated pursuant to Section III.13.3.4A or

Section III.15.A.2.1, or withdrawn pursuant to Section III.15.A.2.3, shall instead be allocated to Market Participants based on their pro rata share of all Capacity Load Obligations in the Capacity Zone in which the terminated resource is located.

III.15.8.5.4. Capacity Transfer Rights.

III.15.8.5.4.1. Specifically Allocated CTRs Associated with Transmission Upgrades.

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.15.8.5.1.6.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.15.8.5.1.6.

(e) **Maine Export Interface**. Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine export interface for as long as Casco Bay continues to pay to support the transmission upgrades.

(f) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price in the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price in the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. This value will be divided by the number of days in the month to derive a daily settlement value.

III.15.8.5.4.2. Specifically Allocated CTRs for Pool-Planned Units.

(a) In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive for each Capacity Commitment Period an allocation of CTRs for each such unit that is the product of: (i) the MW quantity of capacity that the unit cleared in the Annual Capacity Auction associated with the Capacity Commitment Period; and (ii) the municipal utility's ownership entitlements in such unit. The CTRs allocated pursuant to this Section may be designated as self-supply quantities as described in Section III.15.2.9. Municipal utility ownership entitlements are set as shown in the table below and are not transferrable.

	Millstone 3	Seabrook	Stonybrook GT 1A	Stonybrook GT 1B	Stonybrook GT 1C	Stonybrook 2A	Stonybrook 2B	Wyman 4
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%

Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%
Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%
Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%

Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%

Allocation of CTRs as described in this Section shall expire on December 31, 2040. If a unit listed in the table above retires prior to December 31, 2040, however, allocation of CTRs for such unit shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Annual Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant (collectively, "WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

(b) For any CTRs specifically allocated pursuant to this Section that are not designated self-supply quantities for the Capacity Commitment Period, the municipal utility entitlement holder shall receive a credit reflecting the value of such remaining CTRs. The value of each remaining CTR shall be calculated as the product of: (i) the Capacity Clearing Price for the Capacity Zone where the load of the municipal utility entitlement holder is located minus the Capacity Clearing Price for the Capacity Zone in which the Pool-Planned Unit is located; and (ii) the remaining MW quantity. This value will be divided by the number of days in the month to derive a daily settlement value.

III.15.8.5.5. Annual Capacity Market Net Charge Amount.

The Annual Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charges; (b) its revenues from any applicable specifically allocated CTRs; and (c) any applicable export charges.

III.15.9. Information Publication and Reporting.

III.15.9.1. Publication of Certain Data Prior to the Annual Capacity Auction.

For each Annual Capacity Auction, no later than one Business Day before the opening of the Annual Capacity Auction Offer Window, the ISO shall publish publicly on its website:

a. which Capacity Zones shall be modeled in the Annual Capacity Auction;
b. the transmission interface limits as determined pursuant to Section III.12.5;
c. which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Annual Capacity Auction;
d. determinations on which new resources have been rejected due to deliverability impacts pursuant to Section III.15.2.3;
e. the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Annual Capacity Auction, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone;
f. for each resource that submitted a Load-Side Relationship Certification, the following information: the resource technology type; which qualifying circumstance in Section III.A.21.1.4 was asserted in the Load-Side Relationship Certification; the relevant state policy asserted in the Load-Side Relationship Certification, if any; whether the ISO accepted or rejected the Load-Side Relationship Certification; and, consequently, whether the resource was subject to a review for the exercise of buyer-side market power; and
g. which resources are qualified to participate in the Annual Capacity Auction, including resource type, Capacity Zone, and Annual Qualified Capacity.

III.15.9.2. Publication of Certain Data After Conducting the Annual Capacity Auction

In addition to the Annual Capacity Auction results information identified by Section III.15.2.11 and Section III.15.4.3 of Market Rule 1, within 15 days of conducting the Annual Capacity Auction, the ISO shall publish publicly on its website:

a. which Capacity Offers, satisfying the requirements of Section III.A.21.1 of Market Rule 1, were not reviewed for an exercise of buyer-side market power because of one of the conditions described in Sections III.A.21.1.1, III.A.21.1.2, or III.A.21.1.4 of Market Rule 1; and the condition met by each such resource;
b. the Internal Market Monitor's determinations made as part of any buyer-side market power review conducted pursuant to Section III.A.21.2 and any Capacity Offer Floor Price determinations made pursuant to Section III.A.21.3 with regard to capacity not previously cleared

in an Annual Capacity Auction or Forward Capacity Auction, and the basis for any such determinations; except that offer price information and any information employed by the Internal Market Monitor in making these determinations related to the potential impact of a Capacity Resource's offer on Capacity Clearing Prices shall not be published publicly;

c. the Internal Market Monitor's determinations regarding Proposed Capacity Offers, including whether the Internal Market Monitor accepted or rejected prices specified in a resource's Proposed Capacity Offer that were subject to Internal Market Monitor review and whether the Internal Market Monitor accepted or rejected the cost components of the resource' offer, which are set forth in Section III.A.22.2.3(a). No offer prices, cost components, or other underlying data shall be published; and,

d. which resources offering capacity not previously offered into an Annual Capacity Auction or Forward Capacity Auction were qualified to participate in the Annual Capacity Auction (this information will include a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations).

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or

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

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

I.2.2. Definitions:

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

Above-Threshold Offer Segment is the total MW quantity of a Capacity Offer that is priced above the Capacity Offer Price Threshold, whether such MW quantity is delimited by only one price-quantity pair or multiple price-quantity pairs submitted as part of the Capacity Offer pursuant to Section III.15.4.1.

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward or Annual Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 or Section III.15 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 or Section III.15.8.2.2 of Market Rule 1.

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

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

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

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

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

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

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

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

Advisory Qualified Capacity Values are the advisory summer and winter Qualified Capacity values, calculated pursuant to Section III.15.2.5.

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

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

AGC is automatic generation control.

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

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

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

Allowable Capacity Offer Price is a price determined by the Internal Market Monitor as part of its review of Proposed Capacity Offers pursuant to Section III.A.22.2.3.

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

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

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

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

Annual Capacity Auction (ACA) is the Annual Capacity Market auction process carried out pursuant to Section III.15.4 of Market Rule 1.

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

Annual Capacity Auction Offer Window is the period described in the Capacity Auction Calendar during which Capacity Offers must be submitted for an Annual Capacity Auction.

Annual Capacity Market is the annual market for procuring capacity in the New England Control Area, as set forth in Section III.15 of Market Rule 1.

Annual Qualified Capacity is the Qualified Capacity calculated pursuant to Section III.15.3 that is used in an Annual Capacity Auction.

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

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

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

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

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, a Distributed Energy Resource participating as part of a Demand Response Distributed Energy Resource Aggregation, a Settlement Only Distributed Energy Resource Aggregation, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

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

Asset Related Demand is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration; (2) a Storage DARD with a consumption capability of at least 0.1 MW; or (3) one or more storage facilities that are not Electric Storage Facilities with an aggregate consumption capability of at least 1 MW.

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

Asset-Specific Going Forward Costs are the net costs of an asset that is part of a Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Generating Capacity Resources as described in Section III.A.22 (for an asset associated with a Capacity Offer price subject to Internal Market Monitor review) or Section III.A.24 (for an asset submitting a Deactivation Notification).

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

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

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

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

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

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

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

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

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

Average Hourly Load Reduction is either: (i) the sum of the On-Peak Demand Capacity Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Capacity Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand Capacity Resource's or Seasonal Peak Demand Capacity Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.15.2.1.1.2.1 or Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the On-Peak Demand Capacity Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Capacity Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. Electrical energy output and Average Hourly Output shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 or Section III.15.2.1.1.2.1 of Market Rule 1 and the ISO New England Manuals.

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

Bankruptcy Code is the United States Bankruptcy Code.

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

Benchmark Scenario is an Economic Study reference scenario that is described in Section 17.2(a) of Attachment K to the OATT.

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

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

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

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

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

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

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

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

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

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

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

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

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

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

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the

provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day); and (8) with respect to Day-Ahead Ancillary Services Offers administered by the ISO, a quantity with a related price for Day-Ahead Ancillary Services (Day-Ahead Ancillary Services Offers may contain multiple prices for each hour).

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

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

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

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

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

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 or Section III.15.6.1, or; (2) a reconfiguration auction, as described in Section III.13.4 or Section III.15.5.

Capacity Auction Calendar is a calendar published on the ISO's website, as described in Section III.15, detailing dates and deadlines associated with Annual Capacity Market participation, Monthly Reconfiguration Auction participation, and monthly Capacity Supply Obligation Bilateral transactions.

Capacity Auction Offer Price Cap is determined pursuant to Section III.15.1.2.1 of Market Rule 1 prior to the Annual Capacity Auction for each Capacity Commitment Period and is the highest price at which capacity may be offered into the Annual Capacity Auction, unless otherwise expressly allowed by the Tariff.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Capacity Market, as described in Section III.13.7.2.3 or III.15.8.2.3 of Market Rule 1.

Capacity Base Payment is the portion of revenue received in the Forward Capacity Market or Annual Capacity Market as described in Section III.13.7.1 or Section III.15.8.1 of Market Rule 1.

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

Capacity Clearing Price is the clearing price in a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1 or resulting from the Annual Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.15.4.2.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market and Annual Capacity Market.

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

Capacity Demonstration Deadline is a monthly deadline described in the Capacity Auction Calendar for completion of the capacity demonstration requirement set forth in Section III.15.2.6 prior to participation in the Annual Capacity Auction, a Monthly Reconfiguration Auction, or a Capacity Supply Obligation Bilateral transaction.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 or Section III.15.8.5.2 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 or Section III.15.6.2 of Market Rule 1.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 or Section III.15.6 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 or Section III.15.6.2 of Market Rule 1.

Capacity Market is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1, or the annual market for procuring capacity in the New England Control Area, as described in Section III.15 of Market Rule 1.

Capacity Market Commercial Operation is defined in Section III.15.2.6 of Market Rule 1.

Capacity Market Deactivation is the permanent removal of a Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource from the Capacity Market, or the permanent reduction in Capacity Network Import Capability of an External Elective Transmission Upgrade, as described in Section II.I of the OATT.

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

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

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

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

Capacity Offer is an offer submitted for inclusion in the Annual Capacity Auction as set forth in Section III.15.4.1 of Market Rule 1.

Capacity Offer Floor Price is defined in Section III.A.21.3 of Market Rule 1.

Capacity Offer Price Threshold (COPT) is the price specified in Section III.A.22.2.1 of Market Rule 1 associated with the submission, review, and mitigation of prices specified in Capacity Offers submitted for the Annual Capacity Auction.

Capacity Offer Review Submission Deadline is the deadline described in the Capacity Auction Calendar by which proposed Capacity Offers and accompanying documentation must be submitted to the Internal Market Monitor in accordance with Section III.A.22.2.2.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 or Section III.15.8.2 of Market Rule 1.

Capacity Performance Payment Rate is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 or Section III.15.8.2.5 of Market Rule 1.

Capacity Resource is a type of resource eligible to participate in the Annual Capacity Auction. There are four types of Capacity Resources: Generating Capacity Resource, Import Capacity Resource, Demand Capacity Resource, and Distributed Energy Capacity Resource.

Capacity Performance Score is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 or Section III.15.8.2.4 of Market Rule 1.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Capacity Market, as described in Section III.13.7.2.1 or III.15.8.7.2.1 of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2 or an Annual Capacity Auction in accordance with Section III.15.4, a reconfiguration auction in accordance with Section III.13.4 or Section III.15.5, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 or Section III.15.6.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 or Section III.15.6.1 of Market Rule 1.

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4 or Section III.15.8.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 or Section III.15.6.1, or; (2) a reconfiguration auction, as described in Section III.13.4 or Section III.15.5.

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

Capacity Zone Demand Curves are the demand curves used in the Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3 and in Sections III.15.1.1.2 and III.15.1.1.3.

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

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

Category B Designated Blackstart Resource has the same meaning as Designated Blackstart Resource.

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

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

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

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset, the demand reduction capability of a Demand Response Resource, or the demand reduction capability and energy injection capability of a Demand Response Distributed Energy Resource Aggregation.

Cluster has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

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

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

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

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

Cluster Request Window has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

Cluster Restudy has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

Cluster Study has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

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

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

Commercial Capacity is capacity that has achieved FCM Commercial Operation or Capacity Market Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

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

Common Costs are those costs associated with a Station that are avoided only if none of the Generating Capacity Resources composing the Station acquire a Capacity Supply Obligation for the Capacity

Commitment Period, or by the acceptance of the Deactivation Notification of all Generating Capacity Resources composing the Station.

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

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

Composite Capacity Market Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction or Annual Capacity Auction in which multiple Lead Market Participants provide capacity, as described in Section III.13.1.5 or Section III.15.2.8 of Market Rule 1.

Composite Offer Deadline is the deadline for submission of the Composite Offer Form described at Section III.15.2.8.

Composite Offer Form is a form submitted by Lead Market Participants for separate resources seeking to participate as a single composite Capacity Resource in the Annual Capacity Auction, as described in Section III.15.2.8.

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

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

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

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

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the billing process in any billing period.

Continuous Storage ATRR is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage DARD is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Generator Asset is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and
(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Controllable Behind-the-Meter Generation means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.

Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost-Based Reference Price is a price determined by the Internal Market Monitor for comparison to a price in a Proposed Capacity Offer submitted pursuant to Section III.A.22.2.3.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4 and for each Annual Capacity Auction pursuant to Section III.15.1.2.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO in the form of credit insurance coverage.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Cyber Security Exigency is a suspicious or malicious electronic act or event that compromises or attempts to compromise, or disrupts or attempts to disrupt, the ongoing operation of the ISO, the New England Markets, or reliability within the New England Control Area or other electrical facilities directly or indirectly connected to the New England Transmission System and (i) whose severity or nature reasonably requires that the ISO obtain expert assistance not normally called upon to counter such an electronic act or resolve such an event or (ii) whose nature requires the ISO to report such an electronic act or event pursuant to NERC Critical Infrastructure Protection Reliability Standards or applicable regulations promulgated by the Department of Homeland Security, the Department of Energy, or a federal agency with similar cybersecurity responsibilities (or any of their respective successor organizations or agencies).

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Ancillary Services means Day-Ahead Flexible Response Services and Day-Ahead Energy Imbalance Reserve.

Day-Ahead Ancillary Services Avoidable Input Cost is defined in Section III.A.8.2.2 of Appendix A of Market Rule 1.

Day-Ahead Ancillary Services Benchmark Level is defined in Section III.A.8.2 of Appendix A of Market Rule 1.

Day-Ahead Ancillary Services Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Day-Ahead Ancillary Services Offer. Blocks of the Day-Ahead Ancillary Services Offer in effect for each hour will be totaled to determine the quantity of Day-Ahead Ancillary Services Offer Block-Hours for a given day.

Day-Ahead Ancillary Services Expected Close-Out Component is defined in Section III.A.8.2.1 of Appendix A of Market Rule 1.

Day-Ahead Ancillary Services Market means the sale of and payment for Day-Ahead Ancillary Services developed by the ISO as a result of the offers and specifications submitted in accordance with Sections III.1.8 and III.1.10 of Market Rule 1.

Day-Ahead Ancillary Services Offer is an offer that may be submitted by Market Participants in the Day-Ahead Ancillary Services Market in accordance with Section III.1.8.1 of Market Rule 1, and that is used by the ISO to determine obligations for Day-Ahead Ancillary Services as described in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Ancillary Services Strike Price is specified in Section III.1.8.2 of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Energy Imbalance Reserve is a form of reserve capability that is procured in the Day-Ahead Ancillary Services Market to help satisfy the Forecast Energy Requirement Demand Quantity described in Section III.1.8.4 of Market Rule 1.

Day-Ahead Energy Imbalance Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Sections III.1.8 and III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead Flexible Response Services means Day-Ahead Ten-Minute Spinning Reserve, Day-Ahead Ten-Minute Non-Spinning Reserve, and Day-Ahead Thirty-Minute Operating Reserve.

Day-Ahead Flexible Response Services Demand Quantities means Day-Ahead Ten-Minute Spinning Reserve Demand Quantity, Day-Ahead Total Ten-Minute Reserve Demand Quantity, Day-Ahead Minimum Total Reserve Demand Quantity, and Day-Ahead Total Reserve Demand Quantity.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(k) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(j) of Market Rule 1.

Day-Ahead Market means the jointly optimized Day-Ahead Energy Market and Day-Ahead Ancillary Services Market.

Day-Ahead Minimum Total Reserve Demand Quantity is described in Section III.1.8.3(c) of Market Rule 1.

Day-Ahead Prices means the prices resulting from the Day-Ahead Market as described in Section III.2.6 of Market Rule 1.

Day-Ahead Ten-Minute Non-Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

Day-Ahead Ten-Minute Non-Spinning Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Demand Quantity is described in Section III.1.8.3(a) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Obligation is described in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Thirty-Minute Operating Reserve is a form of reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

Day-Ahead Thirty-Minute Operating Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Total Ten-Minute Reserve Demand Quantity is described in Section III.1.8.3(b) of Market Rule 1.

Day-Ahead Total Reserve Demand Quantity is described in Section III.1.8.3(d) of Market Rule 1.

DDP Dispatchable Resource is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource's Dispatch Instructions.

Deactivation Notification is a notification of the planned New England Market Deactivation or Capacity Market Deactivation of a resource, External Elective Transmission Upgrade, or portion thereof, submitted to the ISO by the applicable Lead Market Participant.

Deactivation Notification Deadline is the deadline for submission of a Deactivation Notification and a Deactivation Notification Package, as discussed in Section II.52.1 of the OATT.

Deactivation Notification Package is information submitted to the ISO, as specified in Section II.52.3 of the OATT, by a resource or External Elective Transmission Upgrade seeking a determination regarding a Deactivation Notification.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Bid Cap is $2,000/MWh.

Demand Capacity Resource is a type of resource that may participate in the Capacity Market. There are three Demand Capacity Resource types: Active Demand Capacity Resource, On-Peak Demand Capacity Resource, and Seasonal Peak Demand Capacity Resource.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Demand Reduction Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Demand Reduction Offer Block-Hours.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Distributed Energy Resource Aggregation (DRDERA) is a type of Distributed Energy Resource Aggregation that is described in additional detail in Section III.6.5.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

Demand Response Resource Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20 Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

Dispatchable Asset Related Demand (DARD) is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions, and must meet the technical requirements specified in the ISO New England Operating Procedures and Manuals.

Dispatchable Resource is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Energy Capacity Resource (DECR) is a type of Capacity Resource that participates in the Capacity Market and composes one or more Distributed Energy Resource Aggregations.

Distributed Energy Resource (DER) is any resource located on the distribution system, any subsystem thereof or behind a customer meter that is capable of providing energy injection, energy withdrawal, regulation, or demand reduction.

Distributed Energy Resource Aggregation (DERA) is an aggregation of Distributed Energy Resources that is registered under Section III.6.7 and is described in additional detail in Section III.6.

Distributed Energy Resource Aggregator (DER Aggregator) is a Market Participant that aggregates one or more Distributed Energy Resources for participation in a Distributed Energy Resource Aggregation and serves as the Lead Market Participant for a Distributed Energy Resource Aggregation.

Distributed Generation means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

DRR Aggregation Zone is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

Do Not Exceed (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

Dynamic De-List Bid is a bid submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, Existing Demand Capacity Resources, and Existing Distributed Energy Capacity

Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output, reduction, or consumption level to which a Resource would have been dispatched, based on the Resource's Supply Offer, Demand Reduction Offer, or Demand Bid and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must

maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study or Economic Studies are studies conducted by the ISO pursuant to the process set out in Section 17 of Attachment K to the OATT.

Effective Offer is the Supply Offer, Demand Reduction Offer, Demand Bid or Day-Ahead Ancillary Services Offer that is used for NCPC calculation purposes as specified in Section III.F.1(a).

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electric Storage Facility is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation as determined by the ISO settlement process for the Energy Market.

Energy Offer Floor is negative $150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, Day-Ahead Ancillary Services Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORd) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

Existing Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Retirement Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

Existing Distributed Energy Capacity Resource is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.2 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Export Offer Segment is the total MW quantity of a Capacity Offer that is subject to a contract to export capacity outside the New England Control Area during the Capacity Commitment Period associated with the Capacity Offer, whether such MW quantity is delimited by only one price-quantity pair or multiple price-quantity pairs submitted as part of the Capacity Offer pursuant to Section III.15.4.1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

External Transaction Cap is $2,000/MWh for External Transactions other than Coordinated External Transactions and $1,000/MWh for Coordinated External Transactions.

External Transaction Floor is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative $1,000/MWh for Coordinated External Transactions.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected

PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

Fast Start Generator means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Charge Rate is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Commercial Operation is defined in Section III.13.3.8 of Market Rule 1.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20 Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20 Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20 Service Provider, or any other Transmission Owner, in the case of a Schedule 20 Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20 Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20 Service Provider, or any Transmission Owner.

Forecast Energy Requirement Demand Quantity is described in Section III.1.8.4 of Market Rule 1.

Forecast Energy Requirement Penalty Factor is a rate, in $/MWh, that is used within the Day-Ahead Market security-constrained economic commitment and dispatch process to reflect the value of forecast energy requirement shortages and is defined in Section III.2.6.2(d) of Market Rule 1.

Forecast Energy Requirement Price is determined in accordance with Section III.2.6.2(b) of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1. The final Forward Capacity Auction was for the Capacity Commitment Period beginning on June 1, 2027.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is $7,100/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1. As described in Section III.9.1, the final Forward Reserve Procurement Period shall run from October 1, 2024 through February 28, 2025.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a type of resource participating in the Capacity Market that meets the qualification requirements for such a resource type specified in Section III.15.2..

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource is a type of resource participating in the Capacity Market that meets the qualification requirements for such a resource type specified in Section III.15.2.

Inadvertent Energy Revenue is defined in Section III.3.2.1(o) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(p) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled supply at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section II.54.5 of the OATT..

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Initial State of Charge is the State of Charge that an Electric Storage Facility offers at the start of hour one of the Day-Ahead Energy Market.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement", the "Small Generator Interconnection Agreement", or the "Elective Transmission Upgrade Interconnection Agreement" pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures," the "Small Generator Interconnection Procedures," or the "Elective Transmission Upgrade Interconnection Procedures" pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Reliability Operating Limit (IROL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource or an aggregation of wind, solar, run of river hydro and other renewable resources that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 and 2024-2025 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported

by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures (OPs) are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market or Annual Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids, Demand Reduction Offers, Baseline Deviation Offers, or Day-Ahead Ancillary Services Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource. For purposes of the Annual Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of a Capacity Resource.

Limited Energy Resource means a Generator Asset that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

Load Management means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load-Side Relationship Certification is a certification described in Section III.A.21.1.4 that a Lead Market Participant submits as part of a submission of information pursuant to Section III.A.21.1.5 to demonstrate that certain capacity should not be subject to buyer-side market power review.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Longer-Term Transmission Upgrade is any addition, modification, and/or upgrade to the New England Transmission System with a voltage level below 115 kV that is required in connection with the

construction of a Longer-Term Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Section 16 of Attachment K to the OATT.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115 kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 and Section 10 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Longer-Term Proposal is a proposal submitted by a Qualified Transmission Project Sponsor pursuant to Section 16.4(b) of Attachment K to the OATT.

Longer-Term Transmission Solution is the Longer-Term Proposal identified as the preferred solution pursuant to Section 16 of Attachment K to the OATT.

Longer-Term Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT. The 2050 Transmission Study shall be the first Longer-Term Transmission Study.

Longer-Term Transmission Upgrade is an addition, modification, and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Longer-Term Transmission Upgrade PTF classification specified in the OATT and has been included in the Regional System Plan and RSP Project List as a Longer-Term Transmission Upgrade pursuant to the procedures described in Section 16 of Attachment K of the OATT.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is a value calculated as described in Section III.12.2.2 of Market Rule 1.

Maximum Consumption Limit is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Maximum Daily Award Limit is a parameter that may be submitted as part of a Day-Ahead Ancillary Services Offer, as described in Section III.1.8.1, that expresses the maximum total megawatt-hours of Day-Ahead energy offered or bid and Day-Ahead Ancillary Services offered for the next Operating Day.

Maximum Daily Energy Limit is the maximum amount of megawatt-hours that a Limited Energy Resource expects to be able to generate in the next Operating Day.

Maximum Daily Consumption Limit is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

Maximum Facility Load is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

Maximum Interruptible Capacity is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

Maximum Load is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

Maximum Number of Daily Starts is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Maximum State of Charge is the megawatt-hour value of stored energy, submitted by an Electric Storage Facility as part of its Offer Data for a given hour of the Day-Ahead Energy Market, above which the ISO shall not schedule the Electric Storage Facility to receive electricity from the grid.

Measure Life is the estimated time an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the

Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction, Annual Capacity Auction, or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section III.13.1.4.3.1 and Section III.15.2.1.1.2.1 of Market Rule 1 that are submitted by On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1, or as part of the qualification process for the Annual Capacity Auction pursuant to the requirements of Section III.15.2.1.1.2.1 of Market Rule 1, and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource with the monthly settlement

report for the Forward Capacity Market or Annual Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Metered Quantity For Settlement is defined in Section III.3.2.1.1 of Market Rule 1.

Minimum Consumption Limit is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

Minimum Down Time is the number of hours that must elapse after a Generator Asset or Storage DARD has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or Storage DARD can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its

Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

Minimum State of Charge is the megawatt-hour value of stored energy, submitted by an Electric Storage Facility as part of its Offer Data for a given hour of the Day-Ahead Energy Market, below which the ISO shall not schedule the Electric Storage Facility to inject electricity to the grid.

Minimum Time Between Reductions is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

Minimum Total Reserve Requirement, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Payment is the Capacity Market payment described in Section III.13.7.3 or Section III.15.8.3 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly Qualified Capacity is the amount of a resource's Qualified Capacity eligible to participate in a Monthly Reconfiguration Auction or Capacity Supply Obligation Bilateral during the applicable month.

Monthly Real-Time Demand Reduction Obligation is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Reconfiguration Auction is the reconfiguration auction conducted by the ISO each month as described in Section III.13.4.7 for those Monthly Reconfiguration Auctions held for months prior to the Capacity Commitment Period beginning on June 1, 2028 and in Section III.15.5 for those Monthly Reconfiguration Auctions held for months subsequent to the start of the Capacity Commitment Period beginning on June 1, 2028.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the ninth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that

accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require to be economically viable given reasonable expectations of the energy and ancillary services revenues under long-term equilibrium conditions.

Net Regional Clearing Price is described in Section III.13.7.5 or Section III.15.8.5 of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired or deactivated; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired or deactivated, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

Network Upgrades has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource, New Demand Capacity Resource, or New Distributed Energy Capacity Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule

1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is a form applicable to the Forward Capacity Market described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time applicable to the Forward Capacity Market during which a Project Sponsor may submit a New Capacity Show of Interest Form, a New Demand Capacity Resource Show of Interest Form, or a New Distributed Energy Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is a form applicable to the Forward Capacity Market described in Section III.13.1.4.1.1.1 of Market Rule 1.

New Distributed Energy Capacity Resource is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.1 of Market Rule 1.

New Distributed Energy Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4A.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource.

New Distributed Energy Capacity Resource Show of Interest Form is a form applicable to the Forward Capacity Market described in Section III.13.1.4A.1.1.1 of Market Rule 1.

NECEC Transmission LLC (NECEC) is defined in Schedule 20B to Section II of this Tariff.

New England Clean Energy Connect Transmission Line (NECEC Transmission Line) is defined in Schedule 20B to Section II of this Tariff.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets Deactivation is the permanent removal of a Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource from all New England Markets, or the permanent reduction in Capacity Network Import Capability and Network Import Capability of an External Elective Transmission Upgrade, as described in Section II.I of the OATT.

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the Generator Asset is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.2.1 or Section III.15.8.5.2.1.

Non-Commercial Capacity is the capacity of a resource that cleared in a Forward Capacity Auction for periods prior to the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, or otherwise acquired a Capacity Supply Obligation and remains on Critical Path Schedule monitoring as of June 1, 2028, for some or all of its capacity that acquired a Capacity Supply Obligation.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity

Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Dispatchable Resource is any Resource that does not meet the requirements to be a Dispatchable Resource.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

On-Peak Demand Capacity Resource is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement for the Phase I/II HVDC-TF and the NECEC Transmission Operating Agreement for the NECEC Transmission Line. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a Generator Asset or a Load Asset, where such facility is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4 or Section III.15.7.1.5.4.

Passive DR Auditing Period is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Permanent De-list Bid is a bid submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The "Phase I Transfer Capability" is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The "Phase II Transfer Capability" is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point of Interconnection shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Policy Scenario is an Economic Study reference scenario that is described in Section 17.2(c) of Attachment K to the OATT.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the

Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource, New Demand Capacity Resource, or New Distributed Energy Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

Proposed Capacity Offer is an offer submitted to the Internal Market Monitor for its review pursuant to Section III.A.22.2.3.

Proportional Impact Method has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Proxy Capacity Offer is a type of offer used in the Annual Capacity Market.

Proxy De-List Bid was a type of bid used in the Forward Capacity Market.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a

rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Data Submission Deadline is a date specified in the Capacity Auction Calendar by which a Lead Market Participant seeking to have a resource participate in the Annual Capacity Auction must submit qualification materials pursuant to Section III.15.2.1.1.

Qualification Data Submission Package is the package submitted to the ISO by a Lead Market Participant seeking to qualify a resource for the Annual Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral pursuant to Section III.15.2.1.1.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1 and shall apply to all resources subject to Section III.15.A of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined prior to the 2028-2029 Capacity Commitment Period in the Forward Capacity Market qualification processes, or, for the 2028-2029 Capacity Commitment Period

and all Capacity Commitment Periods thereafter, through the Annual Capacity Market qualification and demonstration processes.

Qualified Capacity Challenge and Restoration Plan Submission Window is the period set forth in the Capacity Auction Calendar during which a Lead Market Participant may challenge the ISO-calculated summer and winter Qualified Capacity values of a Capacity Resource or submit a restoration plan to remedy a significant decrease in a Seasonal Qualified Capacity value of a Capacity Resource.

Qualified Capacity Challenge and Restoration Plan Submission Deadline is a date set forth in the Capacity Auction Calendar by which a Lead Market Participant may challenge the ISO-calculated summer and winter Qualified Capacity values of a Capacity Resource or submit a restoration plan to remedy a significant decrease in Qualified Capacity of a Capacity Resource..

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

Rationing Minimum Limit is the MW quantity below which a Capacity Offer may not be rationed in the Annual Capacity Auction.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Capability Audit is an audit that measures the ability of a Reactive Resource to provide or absorb reactive power to or from the transmission system at a specified real power output or consumption.

Reactive Resource is a device that dynamically adjusts reactive power output automatically in Real-Time over a continuous range, taking into account control system response bandwidth, within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set-point voltage and include, but are not limited to, Generator Assets, Dispatchable Asset Related Demands that are part of an Electric Storage Facility, and dynamic transmission devices.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Demand Reduction Obligation is defined in Section III.3.2.1(c) of Market Rule 1.

Real-Time Demand Reduction Obligation Deviation is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 or Section III.15.7.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

Real-Time Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(l) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as described in Section III.1.7.19 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time SATOA Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a System Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses). A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load. A Network Customer's Monthly Regional Network Load shall be calculated in accordance with Section II.21.2 of the OATT.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Resources are those Alternative Technology Regulation Resources and Generator Assets that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, the Annual Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of

generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide system efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1, and that are used within the Day-Ahead Market security-constrained economic commitment and dispatch process to reflect the value of Day-Ahead Flexible Response Services shortages and defined in Section III.2.6.2(c) of Market Rule 1.

Reserve Quantity For Settlement is defined in Section III.10.1 of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, a Demand Response Resource, a Settlement Only Distributed Energy Resource Aggregation, or a Demand Response Distributed Energy Resource Aggregation.

Resource Adequacy Assessment Qualified Capacity is the amount of summer and winter Qualified Capacity determined pursuant to Section III.15.3 of Market Rule 1 for all Capacity Resources identified in Section III.12.7.2(a) of Market Rule 1, at the start of the Resource Adequacy Assessment process that begins in June of the year preceding the relevant Capacity Commitment Period.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid in the Forward Capacity Market to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

Round-Trip Efficiency is a percentage expressing the megawatt-hours of energy that an Electric Storage Facility injects onto the grid per megawatt-hour of energy it receives from the grid.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20 Service Provider (SSP) references Schedule 20A Service Providers and/or Schedule 20B Service Provider.

Schedule 20A Service Provider is defined in Schedule 20A to Section II of this Tariff.

Schedule 20B Service Provider refers to NECEC as defined in Schedule 20B to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

Seasonal Peak Demand Capacity Resource is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Seasonal Qualified Capacity Notification Date is a date described in the Capacity Auction Calendar by which the ISO shall notify Market Participants of their Seasonal Qualified Capacity for the upcoming Capacity Commitment Period.

Seasonal Qualified Capacity Values are the summer and winter Qualified Capacity calculated by the ISO pursuant to Section 15.2.7.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Selected Qualified Transmission Project Sponsor is the Qualified Transmission Project Sponsor that proposed the Phase Two Solution, Stage Two Solution, Longer-Term Proposal, or System Efficiency Transmission Upgrade Proposal that has been identified by the ISO as the preferred Phase Two Solution, Stage Two Solution, Longer-Term Transmission Solution, or System Efficiency Transmission Upgrade Solution.

Selected Qualified Transmission Project Sponsor Agreement is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to

provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction in the Day-Ahead Energy Market, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction subject to the conditions specified in Section III.1.10.1A(b)(iii) and (iv). For an External Transaction in the Real-Time Energy Market, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of LMP. Demand Response Resources are not permitted to Self-Schedule.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Self-Supplied Capacity Resource is described in Section III.15.2.9.1 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that officer.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

Settlement Only Distributed Energy Resource Aggregation (SODERA) is a type of Distributed Energy Resource Aggregation and is described in additional detail in Section III.6.6.

Settlement Only Resources are generators of less than 5 MW of maximum net output when operating at any temperature at or above zero degrees Fahrenheit, that meet the metering, interconnection and other requirements in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solar High Limit is the estimated power output (MW) of a solar Generator Asset given the Real-Time solar and weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Solar Plant Future Availability is the forecasted Real-Time High Operating Limit of a solar Generator Asset, calculated in the manner described in the ISO Operating Documents.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Sponsored Policy Resource is a resource, each asset of which: receives a revenue source, other than revenues from ISO-administered markets, that is supported by a government-regulated rate, charge, or other regulated cost recovery mechanism, and; qualifies as a renewable, clean, zero carbon, or alternative energy asset under a renewable energy portfolio standard, clean energy standard, decarbonization or net-zero carbon standard, alternative energy portfolio standard, renewable energy goal, clean energy goal, or decarbonization or net-zero carbon goal enacted by federal or New England state statute, regulation, or executive or administrative order and as a result of which the asset receives the revenue source.

Stage One Proposal is a first round submission, as defined in Section 4A.6 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.8 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stakeholder-Requested Scenario is an Economic Study reference scenario that is described in Section 17.2(d) of Attachment K to the OATT.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

State of Charge is the total quantity of megawatt-hours available to be injected by an Electric Storage Facility onto the grid.

State-identified Requirement refers to a legal requirement, mandate or policy of a New England state or local government that forms the basis for a Longer-Term Transmission Study request submitted to the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only if none of the Generating Capacity Resources composing the Station acquire a Capacity Supply Obligation for the Capacity Commitment Period, or by deactivating all Generating Capacity Resources composing the Station.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Storage as Transmission-Only Asset (SATOA) is electric storage equipment that: (1) is connected to or to be connected to Pool Transmission Facilities in the New England Transmission System at a voltage level of 115 kV or higher; (2) the ISO approved to be included in the Regional System Plan and RSP Project List as a regulated transmission solution and Pool Transmission Facility pursuant to the regional system planning processes in Attachment K of the OATT; and (3) is capable of receiving energy only from the Pool Transmission Facilities and storing the energy for later injection to the Pool Transmission Facilities.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Storage DARD is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Substation Network Upgrades has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) or Section III.15.3.2.1(b) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market

Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System-Backed Export is defined in Section III.13.7.2.A.1 and Section III.15.8.2.A.1 of Market Rule 1.

System-Backed Export Charge is calculated in accordance with Section III.13.7.2.A.2 and Section III.15.8.2.A.2 of Market Rule 1.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Efficiency Needs Assessment is defined in Section 17.9 of Attachment K to the OATT.

System Efficiency Needs Scenario is an Economic Study reference scenario that is described in Section 17.2(b) of Attachment K to the OATT.

System Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where financial benefits they provide exceed the cost of the transmission addition or upgrade.

System Efficiency Transmission Upgrade Proposal is a proposal submitted by a Qualified Transmission Project Sponsor pursuant to Section 17.12 of Attachment K to the OATT

System Efficiency Transmission Upgrade Solution is the System Efficiency Transmission Upgrade Proposal identified as the preferred solution pursuant to Section 17.12 of Attachment K to the OATT.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Network Upgrades has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

System Operator shall mean ISO New England Inc. or a successor organization.

System Operating Limit (SOL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

System-Wide Capacity Demand Curve is the demand curve used in the Capacity Market as specified in Section III.13.2.2 or Section III.15.1.1.1.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Reserve Requirement is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve (TMSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Spinning Reserve Requirement is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Reserve Requirement, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Constraint Penalty Factors are described in Section III.1.7.5 of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20 Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20 Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; the Schedule 20B Service Provider for NECEC Transmission Line Transmission Service as provided under Schedule 20B of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20 Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

Transitional Cluster Study has the meaning specified in Section I of Schedule 22, Section 1 of 23, and Section I of 25 of the OATT.

Transitional CNR Group Study has the meaning specified in Section I of Schedule 22, Section I of 23, and Section I of 25 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Unsettled FTR Financial Assurance is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1, and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Cap is $2,000/MWh.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Wind High Limit is the estimated power output (MW) of a wind Generator Asset given the Real-Time weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Wind Plant Future Availability is the forecasted Real-Time High Operating Limit of a wind Generator Asset, calculated in the manner described in the ISO Operating Documents.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) or Section III.15.3.2.2(b) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

Zonal Capacity Obligation is calculated in accordance with Section III.13.7.5.2 and Section III.15.8.5.2 of Market Rule 1.

Zonal Reserve Requirement is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

Overview

The procedures and requirements set forth in this ISO New England Financial Assurance Policy shall govern all Applicants, all Market Participants and all Non-Market Participant Transmission Customers. Capitalized terms used in the ISO New England Financial Assurance Policy shall have the meaning specified in Section I.

The purpose of the ISO New England Financial Assurance Policy is (i) to establish minimum criteria for participation in the New England Markets; (ii) to establish a financial assurance policy for Market Participants and Non-Market Participant Transmission Customers that includes commercially reasonable credit review procedures to assess the financial ability of an Applicant, a Market Participant or a Non-Market Participant Transmission Customer to pay for service transactions under the Tariff and to pay its share of the ISO expenses, including amounts under Section IV of the Tariff, and including any applicable Participant Expenses; (iii) to set forth the requirements for alternative forms of security that will be deemed acceptable to the ISO and consistent with commercial practices established by the Uniform Commercial Code that protect the ISO and the Market Participants against the risk of non-payment by other, defaulting Market Participants or by Non-Market Participant Transmission Customers; (iv) to set forth the conditions under which the ISO will conduct business in a nondiscriminatory way so as to avoid the possibility of failure of payment for services rendered under the Tariff; and (v) to collect amounts past due, to collect amounts payable upon billing adjustments, to make up shortfalls in payments, to suspend Market Participants and Non-Market Participant Transmission Customers that fail to comply with the terms of the ISO New England Financial Assurance Policy, to terminate the membership of defaulting Market Participants and to terminate service to defaulting Non-Market Participant Transmission Customers.

I. GROUPS REGARDED AS SINGLE MARKET PARTICIPANTS

In the case of a group of Entities that are treated as a single Market Participant pursuant to Section 4.1 of the Second Restated NEPOOL Agreement (the "RNA"), the group members shall be deemed to have elected to be jointly and severally liable for all debts to Market Participants, PTOs, Non-Market Participant Transmission Customers, NEPOOL and the ISO of any of the group members. For the purposes of the ISO New England Financial Assurance Policy, the term "Market Participant" shall, in the case of a group of members that are treated as a single Market Participant pursuant to Section 4.1 of the RNA, be deemed to refer to the group of members as a whole, and any financial assurance provided

under the ISO New England Financial Assurance Policy will be credited to the account of the group member with the customer identification at the ISO.

II. MARKET PARTICIPANTS' REVIEW AND CREDIT LIMITS

Solely for purposes of the ISO New England Financial Assurance Policy: a "Municipal Market Participant" is any Market Participant that is either (a) a Publicly Owned Entity except for an electric cooperative or an organization including one or more electric cooperatives as used in Section 1 of the RNA or (b) a municipality, an agency thereof, a body politic or a public corporation (i) that is created under the authority of any state or province that is adjacent to one of the New England states, (ii) that is authorized to own, lease and operate electric generation, transmission or distribution facilities and (iii) that has been approved for treatment as a Municipal Market Participant by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee. Market Participants that are not Municipal Market Participants are referred to as "Non-Municipal Market Participants."

A. Minimum Criteria for Market Participation

Any entity participating or seeking to participate in the New England Markets shall comply with the requirements of this Section II.A. For purposes of this Section II.A, the term "customer" shall refer to both Market Participants and Non-Market Participant Transmission Customers and the word "applicant" shall refer to both applicants for Market Participant status and applicants for transmission service from the ISO.

1. Information Disclosure

(a) Each customer and applicant, on an annual basis (by April 30 each year) shall submit a completed information form in the form of (with only minor, non-material changes) and with the information required by Attachment 6 to the ISO New England Financial Assurance Policy. Customer or applicant shall not be required to disclose information required by Attachment 6 if such disclosure is prohibited by law; provided, however, if the disclosure of any information required by Attachment 6 is prohibited by law, then customer or applicant shall use reasonable efforts to obtain permission to make such disclosure. This information shall be treated as Confidential Information, but its disclosure pursuant to subsection (b) below is expressly permitted in accordance with the terms of the ISO New England Information Policy. Customers and applicants may satisfy the requirements above by providing the ISO with filings made to the Securities

and Exchange Commission or other similar regulatory agencies that include substantially similar information to that required above, provided, however, that the customer or applicant must clearly indicate where the specific information is located in those filings. An applicant that fails to provide this information will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this information by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the information to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) The ISO will review the information provided pursuant to subsection (a) above, and will also review whether the customer or applicant or any of the Principals of the customer or applicant are included on any relevant list maintained by the U.S. Office of Foreign Asset Control. If, after review of the information provided pursuant to subsection (a) above or any other information disclosed pursuant to this Section II, the ISO in its sole discretion requires additional information to make its analysis under this subsection (b), the ISO may require additional information from the customer or applicant. If, based on these reviews, the ISO determines that the commencement or continued participation of such customer or applicant in the New England Markets may present an unreasonable risk to those markets or its Market Participants, the Chief Financial Officer of the ISO shall promptly forward to the Participants Committee or its delegate, for its input, such concerns, together with such background materials deemed by the ISO to be necessary for the Participants Committee or its delegate to develop an informed opinion with respect to the identified concerns, including any measures that the ISO may recommend imposing as a condition to the commencement or continued participation in the markets by such customer or applicant (including suspension) or the ISO's recommendation to prohibit or terminate participation by the customer or applicant in the New England Markets. The ISO shall consider the input of the Participants Committee or its delegate before taking any action to address the identified concerns. If the ISO chooses to impose measures other than prohibition (in the case of an applicant) or termination (in the case of a customer) of participation in the New England Markets, then the ISO shall be required to make an informational filing with the Commission as soon as reasonably practicable after taking such action. If the ISO chooses to prohibit (in the case of an applicant) or

terminate (in the case of a customer) participation in the New England Markets, then the ISO must file for Commission approval of such action, and the prohibition or termination shall become effective only upon final Commission ruling. No action by the ISO pursuant to this subsection (b) shall limit in any way the ISO's rights or authority under any other provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy.

2. Risk Management

(a) Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has: (i) either established or contracted for risk management procedures that are applicable to participation in the New England Markets; and (ii) has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) Each applicant prior to commencing activity in the FTR market shall submit to the ISO or its designee the written risk management policies, procedures, and controls, including, if requested by the ISO in its sole discretion, supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant, applicable to its participation in the FTR market relied upon by the Senior Officer of the applicant signing the certificate provided pursuant to Section II.A.2 (a). On an annual basis (by April 30 each year), each Designated FTR Participant with FTR transactions in any of the previous twelve months or in any currently open month

that exceed 1,000 MW per month (on a net basis, as described in the FTR Financial Assurance Requirements provisions in Section VI) shall submit to the ISO or its designee a certificate in the form of Attachment 5 to the ISO New England Financial Assurance Policy stating that, since the customer's delivery of its risk management policies, procedures, and controls (and any supporting documentation, if applicable) or its last certificate pursuant to this Section II.A.2(b), the customer either: (i) has not made any changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable); or (ii) that changes have been made to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) and that all such changes are clearly identified and attached to such certificate. If any such applicant fails to submit the relevant written policies, procedures, and controls, then the applicant will be prohibited from participating in the FTR market. If any such customer fails to provide a certificate in the form of Attachment 5 by end of business on April 30, then the ISO shall issue a notice of such failure to the customer, and if the customer does not provide the certificate to the ISO within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions in the FTR system.

The ISO, at its sole discretion, may also require any applicant or customer to submit to the ISO or its designee the written risk management policies, procedures, and controls, including supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant, that are applicable to its participation in the New England Markets relied upon by the Senior Officer of the applicant or customer signing the certificate provided pursuant to Section II.A.2(a). The ISO may require such submissions based on identified risk factors that include, but are not limited to, the markets in which the customer is transacting or the applicant seeks to transact, the magnitude of the customer's transactions or the applicant's potential transactions, or the volume of the customer's open positions. Where the ISO notifies an applicant or customer that such a submission is required, the submission shall be due within 5 Business Days of the notice. If an applicant fails to submit the relevant written policies, procedures, and controls as required, then the applicant will be prohibited from participating in the New England Markets. If a

customer fails to submit the relevant written policies, procedures, and controls, then the ISO shall issue a notice of such failure to the customer, and if the customer fails to submit the relevant written policies, procedures, and controls to the ISO or its designee within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

The applicant's or customer's written policies, procedures, controls, and any supporting documentation, received by the ISO or its designee pursuant to this subsection (b) shall be treated as Confidential Information.

(c) Where an applicant or customer submits risk management policies, procedures, and controls, or supporting documentation to the ISO or its designee pursuant to any provision of subsection (b) above, the ISO or its designee shall assess that those policies, procedures, and controls conform to prudent risk management practices, which include, but are not limited to: (i) addressing market, credit, and operational risk; (ii) segregating roles, responsibilities, and functions in the organization; (iii) establishing delegations of authority that specify which transactions traders are authorized to enter into; (iv) ensuring that traders have sufficient training in systems and the markets in which they transact; (v) placing risk limits to control exposure; (vi) requiring reports to ensure that risks are adequately communicated throughout the organization; (vii) establishing processes for independent confirmation of executed transactions; and (viii) establishing periodic valuation or mark-to-market of risk positions as appropriate.

Where, as a result of the assessment described above in this subsection (c), the ISO or its designee believes that the applicant's or customer's written policies, procedures, and controls do not conform to prudent risk management practices, then the ISO or its designee shall provide notice to the applicant or customer explaining the deficiencies. The applicant or customer shall revise its policies, procedures, and controls to address the deficiencies within 55 days after issuance of such notice. (If April 30 falls within that 55 day window, the ISO may choose not to require a separate submission on April 30 as described in subsection (b) above.) If an applicant's revised written policies, procedures, and controls do not adequately address the deficiencies identified in the notice, then the applicant will be prohibited from participating in the New England Markets. If a customer's revised written policies, procedures, and controls do not adequately address

the deficiencies identified in the notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

3. Communications

Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has either established or contracted to establish procedures to effectively communicate with and respond to the ISO with respect to matters relating to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy. Such procedures must ensure, at a minimum, that at least one person with the ability and authority to address matters related to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy on behalf of the customer or applicant, including the ability and authority to respond to requests for information and to arrange for additional financial assurance as necessary, is available from 9:00 a.m. to 5:00 p.m. Eastern Time on Business Days. Such procedures must also ensure that the ISO is kept informed about the current contact information (including phone numbers and e-mail addresses) for the person or people described above. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

4. Capitalization

(a) To be deemed as meeting the capitalization requirements, a customer or applicant shall either:

(i) be Rated and have a Governing Rating that is an Investment Grade Rating of BBB-/Baa3 or higher;

(ii) maintain a minimum Tangible Net Worth of one million dollars; or

(iii) maintain a minimum of ten million dollars in total assets, provided that, to meet this requirement, a customer or applicant may supplement total assets of less than ten million dollars with additional financial assurance in an amount equal to the difference between ten million dollars and the customer's or applicant's total assets in one of the forms described in Section X (any additional financial assurance provided pursuant to this Section II.A.4(a) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy).

(b) Any customer or applicant that fails to meet these capitalization requirements will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions of a duration greater than one month in the FTR system or any future transactions for a duration of one month or less except when FTRs for a month are being auctioned for the final time. Such a customer or applicant may enter into future transaction of a duration of one month or less in the FTR system in the case of FTRs for a month being auctioned for the final time. Any customer or applicant that fails to meet these capitalization requirements shall provide additional financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy equal to 25 percent of the customer's or applicant's FTR Financial Assurance Requirements. Any additional financial assurance provided pursuant to this Section II.A.4(b) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

(c) For markets other than the FTR market:

(i) Where a customer or applicant fails to meet the capitalization requirements, the customer or applicant will be required to provide an additional amount of financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy in an amount equal to 25 percent of the customer's or applicant's total financial assurance requirement, excluding the following:

- FTR Financial Assurance Requirements; and
- FCM Delivery Financial Assurance for customers or applicants that are assessed as medium risk or high risk per the Corporate Liquidity

Assessment (as described in Section VII.A below) from the start of the Capacity Commitment Period related to the sixteenth Forward Capacity Auction (i.e., June 1, 2025) or any Capacity Commitment Period thereafter.

(ii) An applicant that fails to provide the full amount of additional financial assurance required as described in subsection (i) above will be prohibited from participating in the New England Markets until the deficiency is rectified. For a customer, failure to provide the full amount of additional financial assurance required as described in subsection (i) above will have the same effect and will trigger the same consequences as exceeding the "100 Percent Test" as described in Section III.B.2.c of the ISO New England Financial Assurance Policy.

(iii) Any additional financial assurance provided pursuant to this Section II.A.4(c) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

5. Additional Eligibility Requirements

All customers and applicants shall at all times be:

(a) An "appropriate person," as defined in sections 4(c)(3)(A) through (J) of the Commodity Exchange Act (7 U.S.C. § 1 *et seq.*);
(b) An "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or
(c) A "person who actively participates in the generation, transmission, or distribution of electric energy," as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

Each customer must demonstrate compliance with the requirements of this Section II.A.5 by submitting to the ISO on or before September 15, 2013 a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the customer is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately

cease all participation in the New England Markets. If the customer is relying on section 4(c)(3)(F) of the Commodity Exchange Act, it shall accompany the certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the customer's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy. The certificate must be signed on behalf of the customer by a Senior Officer of the customer. A customer that fails to provide this certificate by September 15, 2013 shall be immediately suspended and the ISO shall initiate termination proceedings against the customer.

Each applicant must submit with its membership application a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the applicant is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately cease all participation in the New England Markets. If the applicant is relying on section 4(c)(3)(F) of the Commodity Exchange Act, it shall accompany the certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the applicant's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy. The certificate must be signed on behalf of the applicant by a Senior Officer of the applicant.

The ISO, at its sole discretion, may require any applicant or customer to submit to the ISO documentation in support of the certification provided pursuant to this Section II.A.5. If at any time the ISO becomes aware that a customer no longer satisfies the requirements of this Section II.A.5, the customer shall be immediately suspended and the ISO shall initiate termination proceedings against the customer.

6. Prior Uncured Defaults

In addition to, and not in limitation of Section IV of the ISO New England Financial Assurance Policy, an applicant who has a previous uncured payment default must cure such payment default by payment to the ISO of all outstanding and unpaid obligations, as well as meet all requirements for participation in the New England Markets contained in the ISO New England Financial Assurance Policy. For purposes of this Section II.A.6 and the ISO's evaluation of information disclosed pursuant to Section II of the ISO New England Financial Assurance Policy, the ISO will evaluate relevant factors to determine if an entity seeking to participate in the New England Markets under a different name, affiliation, or organization, should be treated as the same customer or applicant that experienced the previous payment default. Such factors may include, but are not limited to, the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base, and the business engaged in prior to the attempted re-entry. Notwithstanding the foregoing, an applicant shall not be required to cure a payment default that has lawfully been discharged pursuant to the U.S. Bankruptcy Code.

B. Proof of Financial Viability for Applicants

Each Applicant must, with its membership application and at its own expense, submit proof of financial viability, as described below, satisfying the ISO requirements to demonstrate the Applicant's ability to meet its obligations. Each Applicant that intends to establish a Market Credit Limit or a Transmission Credit Limit of greater than $0 under Section II.D or Section II.E below must submit to the ISO all current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch (collectively, the "Rating Agencies"). Each Applicant, whether or not it intends to establish a Market Credit Limit or Transmission Credit Limit of greater than $0, must submit to the ISO audited financial statements for the two most recent years, or the period of its existence, if less than two years, and unaudited financial statements for its last concluded fiscal quarter if they are not included in such audited annual financial statements. These unaudited statements must be certified as to their accuracy by a Senior Officer of such Applicant, which, for purposes of ISO New England Financial Assurance Policy, means an officer of the subject entity with the title of vice president (or similar office) or higher,

or another officer designated in writing to the ISO by that officer. These audited and unaudited statements must include in each case, but are not limited to, the following information to the extent available: balance sheets, income statements, statements of cash flows and notes to financial statements, annual and quarterly reports, and 10-K, 10-Q and 8-K Reports. If any of these financial statements are available on the internet, the Applicant may provide instead a letter to the ISO stating where such statement may be located and retrieved. If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO, at the ISO's sole discretion (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-alone subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; or (iii) compiled statements).

In addition, each Applicant, whether or not it intends to establish a Market Credit Limit or a Transmission Credit Limit, must submit to the ISO: (i) at least one (1) bank reference and three (3) utility company credit references, or in those cases where an Applicant does not have three (3) utility company credit references, three (3) major trade payable vendor references may be substituted; and (ii) relevant information as to any known or anticipated material lawsuits, as well as any prior bankruptcy declarations by the Applicant, or by its predecessor(s), if any; and (iii) a completed ISO credit application. In the case of certain Applicants, some of the information and documentation described in items (i) and (ii) of the immediately preceding sentence may not be applicable or available, and alternate requirements may be specified by the ISO or its designee in its sole discretion.

The ISO will not begin its review of a Market Participant's credit application or the accompanying material described above until full and final payment of that Market Participant's application fee.

The ISO shall prepare a report, or cause a report to be prepared, concerning the financial viability of each Applicant. In its review of each Applicant, the ISO or its designee shall consider all of the information and documentation described in this Section II. All costs

incurred by the ISO in its review of the financial viability of an Applicant shall be borne by such Applicant and paid at the time that such Applicant is required to pay its first annual fee under the Participants Agreement. For an Applicant applying for transmission service from the ISO, all costs incurred by the ISO shall be paid prior to the ISO's filing of a Transmission Service Agreement. The report shall be provided to the Participants Committee or its designee and the affected Applicant within three weeks of the ISO's receipt of that Applicant's completed application, application fee, and Initial Market Participant Financial Assurance Requirement, unless the ISO notifies the Applicant that more time is needed to perform additional due diligence with respect to its application.

C. Ongoing Review and Credit Ratings

1. Rated and Credit Qualifying Market Participants

A Market Participant that (i) has a corporate rating from one or more of the Rating Agencies, or (ii) has senior unsecured debt that is rated by one or more of the Rating Agencies, is referred to herein as "Rated." A Market Participant that is not Rated is referred to herein as "Unrated."

For all purposes in the ISO New England Financial Assurance Policy, for a Market Participant that is Rated, the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt, shall be the "Governing Rating."

A Market Participant that is: (i) Rated and whose Governing Rating is an Investment Grade Rating; or (ii) Unrated and that satisfies the Credit Threshold is referred to herein as "Credit Qualifying." A Market Participant that is not Credit Qualifying is referred to herein as "Non-Qualifying."

For purposes of the ISO New England Financial Assurance Policy, "Investment Grade Rating" for a Market Participant (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the

Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

2. Unrated Market Participants

Any Unrated Market Participant that (i) has not been a Market Participant in the ISO for at least the immediately preceding 365 days; or (ii) has defaulted on any of its obligations under the Tariff (including without limitation its obligations hereunder and under the ISO New England Billing Policy) during such 365-day period; or (iii) is an FTR-Only Customer; or (iv) does not have a Current Ratio of at least 1.0, a Debt-to-Total Capitalization Ratio of 0.6 or less, and an EBITDA-to-Interest Expense Ratio of at least 2.0 must provide an appropriate form of financial assurance as described in Section X below. An Unrated Market Participant that does not meet any of the conditions in clauses (i), (ii), (iii) and (iv) of this paragraph is referred to herein as satisfying the "Credit Threshold."

For purposes of the ISO New England Financial Assurance Policy, "Current Ratio" on any date is all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO; "Debt-to-Total Capitalization Ratio" on any date is a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO; and "EBITDA-to-Interest Expense Ratio" on any date is a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO. The "Debt-to-Total Capitalization Ratio" will not be considered for purposes of determining whether a Municipal Market Participant satisfies the Credit Threshold. Each of the ratios described in this paragraph shall be determined in accordance with international

accounting standards or generally accepted accounting principles in the United States at the time of determination consistently applied.

3. Information Reporting Requirements for Market Participants

Each Market Participant having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis within 10 days of its becoming available and within 65 days after the end of the applicable fiscal quarter of such Market Participant, its balance sheet, which shall show sufficient detail for the ISO to assess the Market Participant's Tangible Net Worth. Unrated Market Participants having a Market Credit Limit or Transmission Credit Limit greater than zero shall also provide additional financial statements, which shall show sufficient detail for the ISO to calculate such Unrated Market Participant's Current Ratio, Debt-to-Total Capitalization Ratio and EBITDA-to-Interest Expense Ratio. In addition, each Market Participant having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of their becoming available and within 120 days after the end of the fiscal year of such Market Participant, balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). If any of this financial information is available on the internet, the Market Participant may provide instead a letter to the ISO stating where such information may be located and retrieved. If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-alone subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; (iii) compiled statements; (iv) internally prepared statements; or (v) tax returns).

Except in the case of a Market Participant or Unrated Market Participant that submits audited financial statements to the ISO, financial statements submitted to the ISO pursuant to this Section II.C.3 shall be accompanied by a written statement from a Senior Officer of the Market Participant or Unrated Market Participant certifying the accuracy of those financial statements. If an attestation was made by an independent accounting firm, then the written statement shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required.

Notwithstanding any other provision in this subsection, the ISO may require any Market Participant to submit the financial statements and other information described in this subsection. The Market Participant shall provide the requested statements and other information within 10 days of such request. If a Market Participant fails to provide financial statements or other information as requested and the ISO determines that the Market Participant poses an unreasonable risk to the New England Markets, then the ISO may request that the Market Participant provide additional financial assurance in an amount no greater than $10 million, or take other measures to substantiate the Market Participant's ability to safely transact in the New England Markets (any additional financial assurance provided pursuant to this Section II.C.3 shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy). If the Market Participant fails to comply with such a request from the ISO, then the ISO may issue a notice of suspension or termination to the Market Participant. If the Market Participant fails to comply with the ISO's request within 5 Business Days from the date of issuance of the notice of suspension or termination, then the ISO may suspend or terminate the Market Participant.

A Market Participant may choose not to submit financial statements as described in this Section II.C.3, in which case the ISO shall use a value of $0.00 for the Market Participant's total assets and Tangible Net Worth for purposes of the capitalization assessment described in Section II.A.4(a) and such Market Participant's Market Credit Limit and Transmission Credit Limit shall be $0.00.

A Market Participant may choose to provide additional financial assurance in an amount equal to $10 million in lieu of providing financial statements under this Section II.C.3.

Such amount shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy but shall be sufficient to meet the capitalization requirements in Section II.A.4(a)(iii).

D. Market Credit Limits

A credit limit for a Market Participant's Financial Assurance Obligations except FTR Financial Assurance Requirements (a "Market Credit Limit") shall be established for each Market Participant in accordance with this Section II.D.

1. Market Credit Limit for Non-Municipal Market Participants

A "Market Credit Limit" shall be established for each Rated Non-Municipal Market Participant in accordance with subsection (a) below, and a Market Credit Limit shall be established for each Unrated Non-Municipal Market Participant in accordance with subsection (b) below.

a. Market Credit Limit for Rated Non-Municipal Market Participants

As reflected in the following table, the Market Credit Limit of each Rated Non-Municipal Market Participant (other than an FTR-Only Customer) shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Municipal Market Participant's Tangible Net Worth as listed in the following table, (ii) $50 million, or (iii) 20 percent (20%) of the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers ("TADO").

Investment Grade Rating		**Percentage of Tangible Net Worth**
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%
AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%

A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

An entity's "Tangible Net Worth" for purposes of the ISO New England Financial Assurance Policy on any date is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock; (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

b. Market Credit Limit for Unrated Non-Municipal Market Participants

The Market Credit Limit of each Unrated Non-Municipal Market Participant that satisfies the Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Municipal Market Participant's Tangible Net Worth, (ii) $25 million or (iii) 20 percent (20%) of TADO. The Market Credit Limit of each Unrated Non-Municipal Market Participant that does not satisfy the Credit Threshold shall be $0.

2. Market Credit Limit for Municipal Market Participants

The Market Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to the lesser of (i) 20 percent (20%) of TADO and (ii) $25 million. The Market Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum

of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million.

E. Transmission Credit Limits

A "Transmission Credit Limit" shall be established for each Market Participant in accordance with this Section II.E, which Transmission Credit Limit shall apply in accordance with this Section II.E. A Transmission Credit Limit may not be used to meet FTR Financial Assurance Requirements.

1. Transmission Credit Limit for Rated Non-Municipal Market Participants

The Transmission Credit Limit of each Rated Non-Municipal Market Participant shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Municipal Market Participant's Tangible Net Worth as listed in the following table or (ii) $50 million:

Investment Grade Rating		**Percentage of Tangible Net Worth**
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%
AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%
A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

2. Transmission Credit Limit for Unrated Non-Municipal Market Participant

The Transmission Credit Limit of each Unrated Non-Municipal Market Participant that satisfies the Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Municipal Market Participant's Tangible Net

Worth or (ii) $25 million. The Transmission Credit Limit of each Unrated Non-Municipal Market Participant that does not satisfy the Credit Threshold shall be $0.

3. Transmission Credit Limit for Municipal Market Participants

The Transmission Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to $25 million. The Transmission Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million.

F. Credit Limits for FTR-Only Customers

The Market Credit Limit and Transmission Credit Limit of each FTR-Only Customer shall be $0.

G. Total Credit Limit

The sum of a Rated Non-Municipal Market Participant's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change, each Rated Non-Municipal Market Participant that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the limit set forth in Section II.D.1.a above) and its Transmission Credit Limit (up to the limit set forth in Section II.E.1 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Municipal Market Participant may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Municipal Market Participant does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates. If the sum of the amounts for Affiliates is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate,

or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

III. MARKET PARTICIPANTS' REQUIREMENTS

Each Market Participant that provides the ISO with financial assurance pursuant to this Section III must provide the ISO with financial assurance in one of the forms described in Section X below and in an amount equal to the amount required in order to avoid suspension under Section III.B below (the "Market Participant Financial Assurance Requirement"). A Market Participant's Market Participant Financial Assurance Requirement shall remain in effect as provided herein until the later of (a) 150 days after termination of the Market Participant's membership or (b) the end date of all FTRs awarded to the Market Participant and the final satisfaction of all obligations of the Market Participant providing that financial assurance; provided, however that financial assurances required by the ISO New England Financial Assurance Policy related to potential billing adjustments chargeable to a terminated Market Participant shall remain in effect until such billing adjustment request is finally resolved in accordance with the provisions of the ISO New England Billing Policy. Furthermore and without limiting the generality of the foregoing, (i) any portion of any financial assurance provided under the ISO New England Financial Assurance Policy that relates to a Disputed Amount shall not be terminated or returned prior to the resolution of such dispute, even if the Market Participant providing such financial assurance is terminated or voluntarily terminates its MPSA and otherwise satisfies all of its obligations to the ISO and (ii) the ISO shall not return or permit the termination of any financial assurance provided under the ISO New England Financial Assurance Policy by a Market Participant that has terminated its membership or been terminated to the extent that the ISO determines in its reasonable discretion that that financial assurance will be required under the ISO New England Financial Assurance Policy with respect to an unsettled liability or obligation owing from that Market Participant.

A Market Participant that knows that it is not satisfying its Market Participant Financial Assurance Requirement shall notify the ISO immediately of that fact.

A. Determination of Financial Assurance Obligations

For purposes of the ISO New England Financial Assurance Policy:

(i) a Market Participant's "Hourly Requirements" at any time will be the sum of (x) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Hourly

Charges (excluding Daily FCM Charges) for such Market Participant that have been settled but not invoiced, plus (z) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been cleared but not settled which amount shall be calculated by the Hourly Charges Estimator. The Hourly Charges Estimator (which amount shall not be less than $0) shall be determined by the following formula:

$$\text{Hourly Charges Estimator} = \sum_{i=t-n+1}^{t} HC_i \times \text{LMP ratio} \times 1.15$$

Where:

t = The last day that such Market Participant's Hourly Charges (excluding Daily FCM Charges) are fully settled;

n = The number of days that such Market Participant's Day-Ahead Energy has been cleared but not settled;

HC = The Hourly Charges (excluding Daily FCM Charges) for such Market Participant for a fully settled day; and

LMP ratio = The average Day-Ahead Prices at the New England Hub over the period of cleared but not settled n days divided by the average Day-Ahead Prices at the New England Hub over the period of most recent fully settled n days. For purposes of this Section III.A.(i), the "New England Hub" shall mean the Hub located in Western and Central Massachusetts referred to as .H.INTERNAL_HUB;

(ii) A Market Participant's "Daily FCM Requirements" at any time will be the sum of (x) the Daily FCM Charges that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Daily FCM Charges that have been settled but not invoiced, plus (z) the Daily FCM Charges for such Market Participant that have been incurred but not settled which amount shall be calculated by the Daily FCM Obligation Estimator. The Daily FCM Obligation Estimator (which amount shall not be less than $0) shall be determined by the following formula:

Daily FCM Obligation Estimator = MAX(FCM_Daily_Credit_CM x NDAY_CM + FCM_Daily_Credit_PM x NDAY_PM + FCM_Charge_LD x NDAY_P2 x FCA_Price_Ratio, 0)

Where:

FCM_Daily_Credit_CM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the current month;

FCM_Daily_Credit_PM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the month preceding the current month;

NDAY_CM is the number of days in the current month within the period from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

NDAY_PM is the number of days in the month preceding the current month within the period from the last day of the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

FCM_Charge_LD is the portion of the Daily FCM Charges that corresponds to Capacity Load Obligations for the Market Participant from the last day the Daily FCM Charges have been settled; and

NDAY_P2 is the number of days from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed) plus 2.

The FCA_Price_Ratio shall be calculated as the weighted average of the Capacity Clearing Prices for the Rest-of-Pool Capacity Zone for the relevant Capacity Commitment Periods divided by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day the Daily FCM Charges have been settled, as determined by the following formula:

$$FCA_Price_Ratio = (((Clearing\ Price_CCP_n \times NDAY_P2_CCP_n) + (Clearing\ Price_CCP_{n+1} \times NDAY_P2_CCP_{n+1}))/NDAY_P2)/(Clearing\ Price_CCP_n)$$

Where:

Clearing Price_CCP_n is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day that the Daily FCM Charges have been settled;

Clearing Price_CCP_{n+1} is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone for the Capacity Commitment Period following CCP_n;

NDAY_P2_CCP_n is number of days in the CCP_n within NDAY_P2; and

NDAY_P2_CCP_{n+1} is number of days in the CCP_{n+1} within NDAY_P2.

(iii) a Market Participant's "Non-Hourly Requirements" at any time will be determined by averaging that Market Participant's Non-Hourly Charges but not include: (A) the amount due from or to such Market Participant for FTR transactions, (B) any amounts due from such Market Participant for the Forward Capacity Market or System-Backed Export transactions, (C) any amounts due under Section 14.1 of the RNA, (D) any amounts due for NEPOOL GIS API Fees, and (E) the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Market Participant) over the two most recently invoiced calendar months; provided that such Non-Hourly Requirements shall in no event be less than zero;

(iv) a Market Participant's "Transmission Requirements" at any time will be determined by averaging that Market Participant's Transmission Charges over the two most recently invoiced calendar months; provided that such Transmission Requirements shall in no event be less than $0;

(v) a Market Participant's Virtual Requirements at any time will equal the amount of all unsettled Increment Offers and Decrement Bids submitted by such Market Participant at such time (which amount of unsettled Increment Offers and Decrement Bids will be calculated by the ISO according to a methodology approved from time to time by the NEPOOL Budget and Finance Subcommittee and posted on the ISO's website);

(vi) a Market Participant's "Financial Assurance Obligations" at any time will be equal to the sum at such time of:

a. such Market Participant's Hourly Requirements; plus
b. such Market Participant's Daily FCM Requirements; plus
c. such Market Participant's Virtual Requirements; plus
d. such Market Participant's Non-Hourly Requirements times 2.50 (subject to Section X.D with respect to Provisional Members); plus
e. such Market Participant's "FTR Financial Assurance Requirements" under Section VI below; plus
f. such Market Participant's "FCM Financial Assurance Requirements" under Section VII below; plus

g. such Market Participant's "IEP Financial Assurance Requirement" under Section III.D below; plus

h. the amount of any Disputed Amounts received by such Market Participant; and

(vii) a Market Participant's "Transmission Obligations" at any time will be such Market Participant's Transmission Requirements times 2.50.

To the extent that the calculations of the components of a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) as described above produce positive and negative values, such components may offset each other; provided, however, that a Market Participant's Financial Assurance Obligations shall never be less than zero.

B. Credit Test Calculations and Allocation of Financial Assurance, Notice and Suspension from the New England Markets

1. Credit Test Calculations and Allocation of Financial Assurance

The financial assurance provided by a Market Participant shall be applied as described in this Section.

(a) "Market Credit Test Percentage" is equal to a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) divided by the sum of its Market Credit Limit and any financial assurance allocated as described in subsection (d) below.

(b) "FTR Credit Test Percentage" is equal to a Market Participant's FTR Financial Assurance Requirements divided by any financial assurance allocated as described in subsection (d) below.

(c) "Transmission Credit Test Percentage" is equal to a Market Participant's Transmission Obligations divided by the sum of its Transmission Credit Limit and any financial assurance allocated as described in subsection (d) below.

(d) A Market Participant's financial assurance shall be allocated as follows:

(i) financial assurance shall be first allocated so as to ensure that the Market Participant's Market Credit Test Percentage is no greater that 100%;

(ii) any financial assurance that remains after the allocation described in subsection (d) (i) shall be allocated so as to ensure that the Market Participant's FTR Credit Test Percentage is no greater than 100%;

(iii) any financial assurance that remains after the allocation described in subsection (d) (ii) shall be allocated so as to ensure that the Market Participant's Transmission Credit Test Percentage is no greater than 100%;

(iv) if any financial assurance remains after the allocations described in subsection (d) (iii), then that remaining financial assurance shall be allocated by repeating the steps described in subsections (d) (i), (d) (ii), and (d) (iii) to ensure that the respective test percentages are no greater than 89.99%;

(v) if any financial assurance remains after the allocation described in subsection (d) (iv), then that remaining financial assurance shall be allocated by repeating the steps described in subsections (d) (i), (d) (ii), and (d) (iii) to ensure that the respective test percentages are no greater than 79.99%;

(vi) any financial assurance that remains after the allocations described in subsection (d) (v) shall be allocated to the Market Credit Test Percentage.

2. Notices

a. 80 Percent Test

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%), the ISO shall issue notice thereof to such Market Participant.

b. 90 Percent Test

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage equals or exceeds 90 percent (90%) , then, in addition to the actions to be taken when the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%), the ISO shall issue notice thereof to such Market Participant. The ISO shall also issue a 90 percent (90%) notice to a Market Participant and take certain other actions under the circumstances described in Section III.B.2.c below.

c. 100 Percent Test

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) or when the sum of the financial assurance and credit limits of a Market Participant that has financial assurance requirements equal zero, then, in addition to the actions to be taken when the

Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%) and 90 percent (90%), (i) the ISO shall issue notice thereof to such Market Participant, (ii) that Market Participant shall be immediately suspended from submitting Increment Offers and Decrement Bids until such time when its Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are less than or equal to 100 percent (100%), and (iii) if sufficient financial assurance to lower the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 100 percent (100%) or, in the case of a Market Participant that has received one to five notices that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) in the previous 365 days (not including the instant notice), sufficient financial assurance to lower such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 90 percent (90%), is not provided by 8:30 a.m. Eastern Time on the next Business Day, (a) the event shall be a Financial Assurance Default; (b) the ISO shall issue notice thereof to such Market Participant, to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contacts for all Market Participants, and (c) such Market Participant shall be suspended from: (1) the New England Markets, as provided below; (2) receiving transmission service under any existing or pending arrangements under the Tariff or scheduling any future transmission service under the Tariff; (3) voting on matters before the Participants Committee and NEPOOL Technical Committees; (4) entering into any future transactions in the FTR system; and (5) submitting an offer of Non-Commercial Capacity in any Forward Capacity Auction or any reconfiguration auction in the Forward Capacity Market, in each case until such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are at 100 percent (100%) or less. In addition to all of the provisions above, any Market Participant that has received six or more notices in the previous 365 days that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage has exceeded 100 percent (100%) shall receive a notice thereof and shall be required to maintain sufficient financial assurance to keep such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage at less than or equal to 90

percent (90%). If such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage exceeds 90 percent (90%), the ISO shall issue a notice thereof to such Market Participant. If sufficient financial assurance to lower such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 90 percent (90%) is not provided by 8:30 a.m. Eastern Time on the next Business Day, then the consequences described in subsections (a), (b) and (c) of Section III.B.2.c (iii) above shall apply until such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are at 90 percent (90%) or less.

However, when a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) or 90 percent (90%), as applicable under this Section III.B.2.c, solely because its Investment Grade Rating is downgraded by one grade and the resulting grade is BBB-/Baa3 or higher, then (x) for five Business Days after such downgrade, such downgrade shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage and (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such downgrade if such Market Participant cures such default within such five Business Day period. When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent solely because a letter of credit is valued at $0 prior to the termination of that letter of credit, as described in Section X.B, then the ISO, in its sole discretion, may determine that: (x) for five Business Days after such change in the valuation of the letter of credit, such valuation shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage; and/or (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such valuation if such Market Participant cures such default within such five Business Day period.

Notwithstanding the foregoing, a Market Participant shall neither (x) receive a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) nor (y) be suspended under this Section

III.B if (i) the amount of financial assurance necessary for that Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to get to 100 percent (100%) or lower is less than $1,000 or (ii) that Market Participant's status with the ISO has been terminated.

3. Suspension from the New England Markets

a. General

The suspension of a Market Participant, and any resulting annulment, termination or removal of OASIS reservations, removal from the settlement system and the FTR system, suspension of the ability to offer Non-Commercial Capacity or participate in a substitution auction in the Forward Capacity Market, drawing down of financial assurance, rejection of Increment Offers and Decrement Bids, and rejection of bilateral transactions submitted to the ISO, shall not limit, in any way, the ISO's right to invoice or collect payment for any amounts owed (whether such amounts are due or becoming due) by such suspended Market Participant under the Tariff or the ISO's right to administratively submit a bid or offer of a Market Participant's Non-Commercial Capacity in any Forward Capacity Auction or any reconfiguration auction or to make other adjustments under Market Rule 1.

In addition to the notices provided herein, the ISO will provide any additional information required under the ISO New England Information Policy.

Each notice issued by the ISO pursuant to this Section III.B shall indicate whether the subject Market Participant has a registered load asset. If the ISO has issued a notice pursuant to this Section III.B and subsequently the subject Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are equal to or less than 100 percent (100%), such Market Participant may request the ISO to issue a notice stating such fact. However, the ISO shall not be obligated to issue such a notice unless, in its sole discretion, the ISO concludes that such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are equal to or less than 100 percent (100%).

Notwithstanding the foregoing, if a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 90 percent (90%) as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, and, but for such Increment Offers and/or Decrement Bids or such bilateral transactions, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, a notice will not be issued.

If a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, and, but for such Increment Offers and/or Decrement Bids or such bilateral transactions, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, a notice will be issued only to such Market Participant, and such Market Participant shall be "suspended" as described below.

Any such suspension as a result of one or more Increment Offers or Decrement Bids submitted by a Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, shall take effect immediately upon submission of such Increment Offers and/or Decrement Bids or such bilateral transactions to remain in effect until such Market Participant is in compliance with the ISO New England Financial Assurance Policy, notwithstanding any provision of this Section III.B to the contrary.

If a Market Participant is suspended from the New England Markets in accordance with the provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy, then the provisions of this Section III.B shall control notwithstanding any other provision of the Tariff to the contrary. A suspended Market Participant shall have no ability so long as it is suspended (i) to be reflected in the ISO's settlement system, including any bilateral transactions, as either a purchaser or a seller of any products or services sold through the New England Markets (other than (A) Commercial Capacity and (B) Non-Commercial Capacity during the Non-Commercial

Capacity Cure Period) that cause such suspended Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the Market Participants, (ii) to submit Demand Bids, Decrement Bids or Increment Offers in the New England Markets, (iii) to submit offers for Non-Commercial Capacity in any Forward Capacity Auction or reconfiguration auction or acquire Non-Commercial Capacity through a Capacity Supply Obligation Bilateral, or (iv) to submit supply offers or demand bids in any Forward Capacity Market substitution auction. Any transactions, including bilateral transactions with a suspended Market Participant (other than transactions for (A) Commercial Capacity and (B) Non-Commercial Capacity during the Non-Commercial Capacity Cure Period) that cause such suspended Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the other Market Participants and any Demand Bids, Decrement Bids, Increment Offers, and Export Transactions submitted by a suspended Market Participant shall be deemed to be terminated for purposes of the Day-Ahead Energy Market clearing and the ISO's settlement system. If a Market Participant has provided the financial assurance required for a Capacity Supply Obligation Bilateral or Annual Reconfiguration Transaction, then that Capacity Supply Obligation Bilateral or Annual Reconfiguration Transaction, respectively, will not be deemed to be terminated when that Market Participant is suspended.

b. Load Assets

Any load asset registered to a suspended Market Participant shall be terminated, and the obligation to serve the load associated with such load asset shall be assigned to the relevant unmetered load asset(s) unless and until the host Market Participant for such load assigns the obligation to serve such load to another asset. If the suspended Market Participant is responsible for serving an unmetered load asset, such suspended Market Participant shall retain the obligation to serve such unmetered load asset. If a suspended Market Participant has an ownership share of a load asset, such ownership share shall revert to the Market Participant that assigned such ownership share to such suspended Market Participant. If a suspended Market Participant has the obligation under the Tariff or otherwise to offer any of its supply or to bid any pumping load to provide products or services sold through the New England Markets, that obligation shall continue, but only in Real-Time, notwithstanding the Market Participant's suspension, and such offer or bid, if cleared under the Tariff, shall be effective.

c. FTRs

If a Market Participant is suspended from entering into future transactions in the FTR system, such Market Participant shall retain all FTRs held by it but shall be prohibited from acquiring any additional FTRs during the course of its suspension. It is intended that any suspension under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy will occur promptly, and the definitive timing of any such suspension shall be determined by the ISO from time to time as reported to the NEPOOL Budget and Finance Subcommittee, and shall be posted on the ISO website.

d. Virtual Transactions

Notwithstanding the foregoing, if a Market Participant is suspended in accordance with the provisions of the ISO New England Financial Assurance Policy as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant and, but for such Increment Offers and/or Decrement Bids, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, then such suspension shall be limited to (i) the immediate "last in, first out" rejection of pending individual uncleared Increment Offers and Decrement Bids submitted by that Market Participant (it being understood that Increment Offers and Decrement Bids are batched by the ISO in accordance with the time, and that Increment Offers and Decrement Bids will be rejected by the batch); and (ii) the suspension of that Market Participant's ability to submit additional Increment Offers and Decrement Bids unless and until it has complied with the ISO New England Financial Assurance Policy, and the determination of compliance for these purposes will take into account the level of aggregate outstanding obligations of that Market Participant after giving effect to the immediate rejection of that Market Participant's Increment Offers and Decrement Bids described in clause (i).

e. Bilateral Transactions

If the sum of the financial assurance and credit limits of a Market Participant that has financial assurance requirements equals zero and that Market Participant would be in compliance with the ISO New England Financial Assurance Policy but for the submission of bilateral transactions to the ISO to which the Market Participant is a party, or if a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent as a result of one or more bilateral transactions submitted to the ISO to which the Market Participant is a party, then the consequences described in subsection (a) above shall be limited to: (i) rejection of any pending bilateral transactions to which a Market Participant is a party that cause the Market Participant to incur a financial obligation in the ISO's settlement system or any

liability to the ISO, NEPOOL, or the Market Participants, such that the aggregate value of the pending bilateral transactions submitted by all Market Participants is maximized (recognizing the downstream effect that rejection of a bilateral transaction may have on the Market Credit Test Percentages, FTR Credit Test Percentages, or Transmission Credit Test Percentages of other Market Participants), while ensuring that the financial assurance requirements of each Market Participant are satisfied; and (ii) suspension of that Market Participant's ability to submit additional bilateral transactions until it has complied with the ISO New England Financial Assurance Policy (the determination of compliance for these purposes will take into account the level of aggregate outstanding obligations of the Market Participant after giving effect to the immediate rejection of the bilateral transactions to which the Market Participant is a party as described in clause (i) above). In the case of a bilateral transaction associated with the Day-Ahead Energy Market, the ISO will provide notice to a Market Participant that would be in default of the ISO New England Financial Assurance Policy as a result of the bilateral transaction, and the consequences described in clauses (i) and (ii) above shall only apply if the Market Participant fails to cure its default by 6:00 p.m. Eastern Time of that same Business Day. In the case of a Capacity Load Obligation Bilateral, the consequences described in clauses (i) and (ii) above shall apply if the Market Participant does not cure its default within one Business Day after notification that a Capacity Load Obligation Bilateral caused the default. Bilateral transactions that transfer Forward Reserve Obligations and Supplemental Availability Bilaterals are not subject to the provisions of this Section III.B.3(e).

4. Serial Notice and Suspension Penalties

If either (x) a Market Participant is suspended from the New England Markets because of a failure to satisfy its Financial Assurance Requirements in accordance with the provisions of the ISO New England Financial Assurance Policy or (y) a Market Participant receives more than five notices that its Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage has exceeded 100 percent (100%) in any rolling 365-day period, then such Market Participant shall pay a $1,000 penalty for such suspension and for each notice after the fifth notice in a rolling 365-day period. If a Market Participant receives a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage has exceeded 100 percent (100%) in the same day, then only one of those notices will count towards the

five notice limit. All penalties paid under this paragraph shall be deposited in the Late Payment Account maintained under the ISO New England Billing Policy.

C. Additional Financial Assurance Requirements for Certain Municipal Market Participants

Notwithstanding the other provisions of the ISO New England Financial Assurance Policy and in addition to the other obligations hereunder, a Credit Qualifying Municipal Market Participant that is not a municipality (which, for purposes of this Section III.C, does not include an agency or subdivision of a municipality) must provide additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation, unless either: (1) that Credit Qualifying Municipal Market Participant has a corporate Investment Grade Rating from one or more of the Rating Agencies; or (2) that Credit Qualifying Municipal Market Participant has an Investment Grade Rating from one or more of the Rating Agencies for all of its rated indebtedness; or (3) that Credit Qualifying Municipal Market Participant provides the ISO with an opinion of counsel that is acceptable to the ISO confirming that amounts due to the ISO under the Tariff have priority over, or have equal priority with, payments due on the debt on which the Credit Qualifying Municipal Market Participant's Investment Grade Rating is based. Each legal opinion provided under clause (3) of this Section III.C will be updated no sooner than 60 days and no later than 30 days before each reconfiguration auction that precedes a Capacity Commitment Period to which such legal opinion relates, and if that update is not provided or that update is not acceptable to the ISO, the applicable Credit Qualifying Municipal Market Participant must either satisfy one of the other clauses of this Section III.C or provide additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation.

D. Inventoried Energy Program Financial Assurance Requirement

Notwithstanding the other provisions of the ISO New England Financial Assurance Policy and in addition to the other obligations hereunder, if any Market Participant has submitted a Forward Energy Inventory Election approved by the ISO under Section III.K.1.1 of the Tariff, such Market Participant shall be subject to the additional financial assurance requirements of this section. Any such Market Participant must provide additional financial assurance in one of the forms described in Section X below in an

amount equal to the Inventoried Energy Program Financial Assurance Requirement on or before December 1 of each program year. The Inventoried Energy Program Financial Assurance Requirement will be calculated on a daily basis for each program year, from December 1, 2023 through February 29, 2024 and separately from December 1, 2024 through February 28, 2025, as follows:

IEP Financial Assurance Requirement = MAX(0, FE_MWh - Q_MWh) * D_95 * MF * SPR

Where:

FE_MWh = is the amount of Forward Energy Inventory elected by the Market Participant;

Q_MWh = is the maximum observed physical inventory over the prior 15 days;

D_95 = is the 95th percentile of observed Inventoried Energy Days, which for the 2023-2024 and 2024-2025 program years shall be 19;

MF = is the month factor, which shall be 100% for December, 87% for January, and 26% for February; and

SPR = spot payment rate = the $/MWh rate used in the calculation of Inventoried Energy Spot Payments as described in Section III.K.3.2 of the Tariff.

IV. CERTAIN NEW AND RETURNING MARKET PARTICIPANTS REQUIREMENTS

A new Market Participant or a Market Participant other than an FTR-Only Customer, or a Governance Only Member whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months (a "Returning Market Participant") is required to provide the ISO, for three months in the case of a new Market Participant and six months in the case of a Returning Market Participant, financial assurance in one of the forms described in Section X below equal to any amount of additional financial assurance required to meet the capitalization requirements described in Section II.A.4 plus the greater of (a) its Financial Assurance Requirement or (b) its "Initial Market Participant Financial Assurance Requirement." A new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement must be provided to the ISO no later than one Business Day before commencing activity in the New England Markets or commencing transmission service under the Tariff, and shall be determined by the following formula:

$$FAR = G + T + L + E$$

Where FAR is the Initial Market Participant Financial Assurance Requirement and G, T, L and E are determined by the following formulas:

$G = (MW_g \times Hr_{DA} \times D \times 3.25) + (MW_g \times Hr_{MIS} \times S_2 \times 3.25)$;

Where:

MW_g = Total nameplate capacity of the Market Participant's generation units that have achieved commercial operation;

Hr_{DA} = The number of hours of generation that any such generation unit could be bid in the Day-Ahead Energy Market before it could be removed if such unit tripped, as determined by the ISO in its sole discretion;

D = The maximum observed differential between Energy prices in the Day-Ahead and Real-Time Energy Markets during the prior calendar year ("Maximum Energy Price Differential"), as determined by the ISO in its sole discretion;

Hr_{MIS} = The standard number of hours between generation and the issuance of initial Market Information Server ("MIS") settlement reports including projected generation activity for such units, as determined by the ISO in its sole discretion; and

S_2 = The per MW amount assessed pursuant to Schedule 2 of Section IV.A of this Tariff, as determined by the ISO.

T = $MW_t \times Hr_{MIS} \times (D + S_{2\text{-}3}) \times 3.25$;

Where: MW_t = Number of MWs to be traded in the New England Markets as reasonably projected by the new Market Participant or the Returning Market Participant;

Hr_{MIS} = The standard number of hours between generation and the issuance of initial MIS settlement reports including projected generation activity, as determined by the ISO in its sole discretion;

D = Maximum Energy Price Differential; and

S_{2-3} = The per MWh amount assessed pursuant to Schedules 2 and 3 of Section IV.A of the Tariff, as determined annually by the ISO.

$$L = (MW_1 \times LF \times Hr_{MIS} \times (EP + S_{2-3}) \times 3.25) + (MW_1 \times Hr_{MIS} \times TC \times 3.25)$$

Where:

MW_1 = MWs of Real-Time Load Obligation (as defined in Market Rule 1) of the new Market Participant or Returning Market Participant;

LF = Average load factor in New England, as determined annually by the ISO in its sole discretion;

Hr_{MIS} = The standard number of hours between generation and the issuance of initial MIS settlement reports including projected generation activity, as determined by the ISO in its sole discretion;

EP = The average price of Energy in the Day-Ahead Energy Market for the most recent calendar year for which information is available from the Annual Reports published by the ISO, as determined by the ISO in its sole discretion;

S_{2-3} = The per MW amount assessed pursuant to Schedules 2 and 3 of Section IV.A of the Tariff, as determined annually by the ISO; and

TC = The hourly transmission charges per MW_1 assessed under the Tariff (other than Schedules 1, 8 and 9 of Section II of the Tariff), as determined annually by the ISO.

$$E = (SE) \times 3.25$$

Where:

SE = Average monthly share of Participant Expenses for the applicable Sector.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV is 80 percent or more of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equaled or exceeded 80 percent (80%) under Section III.B above.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV is 90 percent or more of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equaled or exceeded 90 percent (90%) under Section III.B above.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV exceeds 100 percent of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeded 100 percent (100%) under Section III.B above.

V. NON-MARKET PARTICIPANT TRANSMISSION CUSTOMERS REQUIREMENTS

A. Ongoing Financial Review and Credit Ratings

1. Rated Non-Market Participant Transmission Customer and Transmission Customers

Each Rated Non-Market Participant Transmission Customer that does not currently have an Investment Grade Rating must provide an appropriate form of financial assurance as described in Section X below.

2. Unrated Non-Market Participant Transmission Customers

Any Unrated Non-Market Participant Transmission Customer that (i) has defaulted on any of its obligations under the Tariff (including without limitation its obligations hereunder and under the ISO New England Billing Policy) during the immediately preceding 365-day period; or (ii) does not have a Current Ratio of at least 1.0, a Debt-to-Total Capitalization Ratio of 0.6 or less, and an EBITDA-to-Interest Expense Ratio of at least 2.0 must provide an appropriate form of financial assurance as described in Section X below. An Unrated Non-Market Participant Transmission Customer that does not meet either of the conditions described in clauses (i) and (ii) of this paragraph is referred to herein as satisfying the "NMPTC Credit Threshold."

B. NMPTC Credit Limits

1. NMPTC Market Credit Limit

A Market Credit Limit shall be established for each Non-Market Participant Transmission Customer as set forth in this Section V.B.1.

The Market Credit Limit of each Rated Non-Market Participant Transmission Customer shall at any time be equal to the least of: (i) the applicable percentage of such Rated Non-Market Participant Transmission Customer's Tangible Net Worth (as reflected in the following table); (ii) $50 million; or (iii) 20 percent (20%) of TADO:

Investment Grade Rating		**Percentage of Tangible Net Worth**
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%
AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%

A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

The Market Credit Limit of each Unrated Non-Market Participant Transmission Customer that satisfies the NMPTC Credit Threshold shall at any time be equal to the least of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Market Participant Transmission Customer's Tangible Net Worth, (ii) $25 million or (iii) 20 percent (20%) of TADO. The Market Credit Limit of each Unrated Non-Market Participant Transmission Customer that does not satisfy the NMPTC Credit Threshold shall be $0.

2. NMPTC Transmission Credit Limit

A Transmission Credit Limit shall be established for each Non-Market Participant Transmission Customer in accordance with this Section V.B.2.

The Transmission Credit Limit of each Rated Non-Market Participant Transmission Customer shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Market Participant Transmission Customer's Tangible Net Worth as listed in the following table or (ii) $50 million:

Investment Grade Rating		**Percentage of Tangible Net Worth**
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%
AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%
A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%

BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

The Transmission Credit Limit of each Unrated Non-Market Participant Transmission Customer that satisfies the NMPTC Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Market Participant Transmission Customer's Tangible Net Worth or (ii) $25 million. The Transmission Credit Limit of each Unrated Non-Market Participant Transmission Customer that does not satisfy the NMPTC Credit Threshold shall be $0.

3. NMPTC Total Credit Limit

The sum of a Non-Market Participant Transmission Customer's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change, each Rated Non-Market Participant Transmission Customer that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the amount set forth in Section V.B.1 above) and its Transmission Credit Limit (up to the amount set forth in Section V.B.2 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Market Participant Transmission Customer may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Market Participant Transmission Customer does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates. If the sum of the amounts for Affiliates is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate, or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

C. Information Reporting Requirements for Non-Market Participant Transmission Customers

Each Rated Non-Market Participant Transmission Customer having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis, within 10 days of their becoming available and within 65 days after the end of the applicable fiscal quarter of such Rated Non-Market Participant Transmission Customer, its balance sheet, which shall show sufficient detail for the ISO to assess the Rated Non-Market Participant Transmission Customer's Tangible Net Worth. In addition, each Rated Non-Market Participant Transmission Customer that has an Investment Grade Rating having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of their becoming available and within 120 days after the end of the fiscal year of such Rated Non-Market Participant Transmission Customer, balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). If any of this financial information is available on the internet, the Rated Non-Market Participant Transmission Customer may provide instead a letter to the ISO stating where such information may be located and retrieved.

Each Unrated Non-Market Participant Transmission Customer having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis, within 10 days of their becoming available and within 65 days after the end of the applicable fiscal quarter of such Unrated Non-Market Participant Transmission Customer, its balance sheet, which shall show sufficient detail for the ISO to assess the Unrated Non-Market Participant Transmission Customer's Tangible Net Worth. Unrated Non-Market Participant Transmission Customers having a Market Credit Limit or Transmission Credit Limit greater than $0 shall also provide additional financial statements, which shall show

sufficient detail for the ISO to calculate such Unrated Non-Market Participant Transmission Customer's Current Ratio, Debt-to-Total Capitalization Ratio and EBITDA-to-Interest Expense Ratio. In addition, each such Unrated Non-Market Participant Transmission Customer that satisfies the Credit Threshold and has a Market Credit Limit or Transmission Credit Limit of greater than $0 or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of becoming available and within 120 days after the end of the fiscal year of such Unrated Non-Market Participant Transmission Customer balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). Where any of the above financial information is available on the internet, the Unrated Non-Market Participant Transmission Customer may provide the ISO with a letter stating where such information may be located and retrieved.

If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-along subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; (iii) compiled statements; (iv) internally prepared statements; or (v) tax returns).

Except in the case of a Non-Market Participant Transmission Customer that submits audited financial statements to the ISO, financial statements submitted to the ISO pursuant to this Section V.C shall be accompanied by a written statement from a Senior Officer of the Non-Market Participant Transmission Customer certifying the accuracy of those financial statements. If an attestation was made by an independent accounting firm, then the written statement shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required.

Notwithstanding any other provision in this subsection, the ISO may require any Non-Market Participant Transmission Customer to submit the financial statements and other information described in this subsection. The Non-Market Participant Transmission Customer shall provide the requested statements and other information within 10 days of such request. If a Non-Market Participant Transmission Customer fails to provide financial statements or other information as requested and the ISO determines that the Non-Market Participant Transmission Customer poses an unreasonable risk to the New England Markets, then the ISO may request that the Non-Market Participant Transmission Customer provide additional financial assurance in an amount no greater than $10 million, or take other measures to substantiate the Non-Market Participant Transmission Customer's ability to safely transact in the New England Markets (any additional financial assurance provided pursuant to this Section V.C shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy). If the Non-Market Participant Transmission Customer fails to comply with such a request from the ISO, then the ISO may issue a notice of suspension or termination to the Non-Market Participant Transmission Customer. If the Non-Market Participant Transmission Customer fails to comply with the ISO's request within 5 Business Days from the date of issuance of the notice of suspension or termination, then the ISO may suspend or terminate the Non-Market Participant Transmission Customer.

A Non-Market Participant Transmission Customer may choose not to submit financial statements as described in this Section V.C, in which case the ISO shall use a value of $0.00 for the Non-Market Participant Transmission Customer's total assets and Tangible Net Worth for purposes of the capitalization assessment described in Section II.A.4(a) and such Non-Market Participant Transmission Customer's Market Credit Limit and Transmission Credit Limit shall be $0.00.

A Non-Market Participant Transmission Customer may choose to provide additional financial assurance in an amount equal to $10 million in lieu of providing financial statements under this Section V.C. Such amount shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy but shall be sufficient to meet the capitalization requirements in Section II.A.4(a)(iii).

D. Financial Assurance Requirement for Non-Market Participant Transmission Customers

Each Non-Market Participant Transmission Customer that provides additional financial assurance pursuant to the ISO New England Financial Assurance Policy must provide the ISO with financial assurance in one of the forms described in Section X below and in the amount described in this Section V.D (the "NMPTC Financial Assurance Requirement").

1. Financial Assurance for ISO Charges

Each Non-Market Participant Transmission Customer must provide the ISO with additional financial assurance such that the sum of its Market Credit Limit and that additional financial assurance shall at all times be at least equal to the sum of:

(i) two and one-half (2.5) times the average monthly Non-Hourly Charges for such Non-Market Participant Transmission Customer over the two most recently invoiced calendar months (which amount shall not in any event be less than $0); plus

(ii) amount of any unresolved Disputed Amounts received by such Non-Market Participant Transmission Customer.

2. Financial Assurance for Transmission Charges

Each Non-Market Participant Transmission Customer must provide the ISO with additional financial assurance hereunder such that the sum of (x) its Transmission Credit Limit and (y) the excess of (A) the available amount of the additional financial assurance provided by that Non-Market Participant Transmission Customer over (B) the amount of that additional financial assurance needed to satisfy the requirements of Section V.D.1 above is equal to two and one-half (2.5) times the average monthly Transmission Charges for such Non-Market Participant Transmission Customer over the two most recently invoiced calendar months (which amount shall not in any event be less than $0)

3. Notice of Failure to Satisfy NMPTC Financial Assurance Requirement

A Non-Market Participant Transmission Customer that knows or can reasonably be expected to know that it is not satisfying its NMPTC Financial Assurance Requirement shall notify the ISO immediately of that fact. Without limiting the availability of any other remedy or right hereunder, failure by any Non-Market Participant Transmission

Customer to comply with the provisions of the ISO New England Financial Assurance Policy (including failure to satisfy its NMPTC Financial Assurance Requirement) may result in the commencement of termination of service proceedings against that non-complying Non-Market Participant Transmission Customer.

VI. ADDITIONAL PROVISIONS FOR FTR TRANSACTIONS

Market Participants must complete an ISO-prescribed training course prior to participating in the FTR Auction. All Market Participants transacting in the FTR Auction that are otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy, including all FTR-Only Customers ("Designated FTR Participants") are required to provide financial assurance in an amount equal to the sum of the FTR Settlement Risk Financial Assurance, the Unsettled FTR Financial Assurance, and the Settlement Financial Assurance, each as described in this Section VI (such sum being referred to in the ISO New England Financial Assurance Policy as the "FTR Financial Assurance Requirements").

A. FTR Settlement Risk Financial Assurance

A Designated FTR Participant is required to provide "FTR Settlement Risk Financial Assurance" for each bid it submits into an FTR Auction and for each FTR that is awarded to it in an FTR Auction, as described below.

After bids are finalized for an FTR Auction, but before the auction results are final, a Designated FTR Participant must provide FTR Settlement Risk Financial Assurance based on its bids for each FTR path. The ISO will calculate an FTR Settlement Risk Financial Assurance amount for each direction (prevailing flow and counter flow) of each FTR path on which the Designated FTR Participant has bid, equal to the total number of MW bid for that direction of the FTR path multiplied by the applicable proxy value for the FTR path (as described below) multiplied by the number of hours associated with the bid. For that FTR path, the Designated FTR Participant must provide FTR Settlement Risk Financial Assurance equal to the higher of the amounts calculated for each direction.

Once an FTR Auction's results are final, a Designated FTR Participant must provide FTR Settlement Risk Financial Assurance based on awarded FTRs, equal to the MW value of each awarded FTR multiplied by the applicable proxy value for the FTR path (as described below) multiplied by the number of hours associated with the FTR. For

purposes of this calculation, the ISO will net the MW values of a Designated FTR Participant's awarded FTRs having the same or opposite path, same contract month, and same type (on-peak or off-peak). For purposes of this netting, annual FTRs may be converted into monthly positions.

The proxy value for each FTR path, which shall be calculated separately for on-peak and off-peak FTRs, will be based on the standard deviation observed in the difference between the average congestion components of the Locational Marginal Price in the Day-Ahead Energy Market at the path's sink and source for the previous 36 months, with differing multipliers for annual and monthly FTRs and for prevailing flow and counter flow paths. These multipliers will be reviewed and approved by the NEPOOL Budget and Finance Subcommittee and shall be posted on the ISO's website. Where there is insufficient data to perform these calculations for a node, zonal data will be used instead.

FTR Settlement Risk Financial Assurance will be adjusted as the awarded FTRs are settled. In no event will the FTR Settlement Risk Financial Assurance be less than $0.

B. Unsettled FTR Financial Assurance

A Designated FTR Participant is required to maintain, at all times, "Unsettled FTR Financial Assurance" for all FTRs awarded to it in any FTR Auctions. Immediately after FTRs are awarded in an FTR Auction, the Unsettled FTR Financial Assurance for those FTRs shall be zero. After subsequent FTR Auctions, the Unsettled FTR Financial Assurance for each FTR awarded in a previous FTR Auction shall be adjusted to reflect any change in the clearing price for that FTR based on non-zero volume. The adjustment will be equal to the change in the clearing price multiplied by the number of MW of the previously awarded FTR, with increases in the clearing price reducing the Unsettled FTR Financial Assurance amount and decreases in the clearing price increasing the Unsettled FTR Financial Assurance amount. For purposes of these calculations, the ISO will consider FTRs having the same or opposite path, same contract month, and same type (on-peak or off-peak) together. A Designated FTR Participant's Unsettled FTR Financial Assurance may be a charge or a credit, and in the case of a credit, may offset the Designated FTR Participant's other FTR Financial Assurance Requirements (but not to less than zero). A Designated FTR Participant's Unsettled FTR Financial Assurance will be adjusted as the awarded FTRs are settled.

C. Settlement Financial Assurance

A Designated FTR Participant that has been awarded a bid in an FTR Auction is required to provide "Settlement Financial Assurance." The amount of a Designated FTR Participant's Settlement Financial Assurance shall be equal to the amount of any settled but uninvoiced Charges incurred by such Designated FTR Participant for FTR transactions less the settled but uninvoiced amounts due to such Market Participant for FTR transactions. These amounts shall include the costs of acquiring FTRs as well as payments and charges associated with FTR settlement. Additionally, when the Designated FTR Participant is invoiced and the net of the charges incurred by such Designated FTR Participant for FTR transactions and the amount due to such Market Participant for FTR transactions results in a net charge, the amount of the net charge shall be added to the Designated FTR Participant's Settlement Financial Assurance until the invoice is paid.

D. Consequences of Failure to Satisfy FTR Financial Assurance Requirements

If a Designated FTR Participant does not have additional financial assurance equal to its FTR Financial Assurance Requirements (in addition to its other financial assurance obligations hereunder) in place at the time an FTR Auction into which it has bid closes, then, in addition to the other consequences described in the ISO New England Financial Assurance Policy, all bids submitted by that Designated FTR Participant for that FTR Auction will be rejected. The Designated FTR Participant will be allowed to participate in the next FTR Auction held provided it meets all requirements for such participation, including without limitation those set forth herein. Each Designated FTR Participant must maintain the requisite additional financial assurance equal to its FTR Financial Assurance Requirements for the duration of the FTRs awarded to it. The amount of any additional financial assurance provided by a Designated FTR Participant in connection with an unsuccessful bid in an FTR Auction which, as a result of such bid being unsuccessful, is in excess of its FTR Financial Assurance Requirements will be held by the ISO and will be applied against future FTR bids by and awards to that Designated FTR Participant unless that Designated FTR Participant requests in writing to have such excess financial assurance returned to it. Prior to returning any financial assurance to a Designated FTR Participant, the ISO shall use such financial assurance to satisfy any overdue obligations of that Designated FTR Participant. The ISO shall only return to that

Designated FTR Participant the balance of such financial assurance after all such overdue obligations have been satisfied.

VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS

Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Forward Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy, and any Market Participant with System-Backed Export transactions (each a "Designated FCM Participant"), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the "FCM Financial Assurance Requirements"). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant.

A. FCM Delivery Financial Assurance

Each Designated FCM Participant that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter, shall be subject to a "Corporate Liquidity Assessment" as described in this Section VII.A to determine its FCM Delivery Financial Assurance.

1. FCM Delivery Financial Assurance Calculation

A Designated FCM Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy. If a Designated FCM Participant's FCM Delivery Financial Assurance is negative, it will be used to reduce the Designated FCM Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements), but not to less than zero.

FCM Delivery Financial Assurance is calculated according to the following formula for a Designated FCM Participant that has a Capacity Supply Obligation up to and including the end of the Capacity Commitment Period associated with the fifteenth Forward Capacity Auction:

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC

FCM Delivery Financial Assurance is calculated according to the following applicable formula for a Designated FCM Participant that has a Capacity Supply Obligation commencing at the beginning of the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction and every Capacity Commitment Period thereafter. The applicable FCM Delivery Financial Assurance formula is determined by the results of a Corporate Liquidity Assessment and is limited by the operation of the applicable stop-loss mechanisms as set forth in Market Rule 1 (including those that may apply in the next Capacity Commitment Period).

Corporate Liquidity Assessment Result: Low Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC

Corporate Liquidity Assessment Result: Medium Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC – Peak Monthly Stop-loss x max[(ABR – CWAP), 0.1]

Corporate Liquidity Assessment Result: High Risk

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC – Peak Monthly Stop-loss x max[(ABR – CWAP), 0.1] – Second Largest Monthly Stop-loss x max[(ABR – CWAP), 0.1]

Where:

MCC (monthly capacity charge) equals monthly capacity payments incurred in previous months, which have not yet been invoiced in instances where the MCC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MCC is a charge to the Designated FCM Participant. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

IMC (intra-month collateral) equals estimated monthly capacity payments incurred during the current delivery month as limited by the difference (which shall in no event be less than zero) between (A) the minimum of the applicable monthly stop-loss and the remaining annual stop-loss as described in Section III.13.7.3.1 and Section III.13.7.3.2 of Market Rule 1, respectively, and (B) the amount of additional FCM Delivery Financial Assurance when considering the Designated FCM Participant's current month FCM Delivery Financial Assurance obligation as compared to the Designated FCM Participant's next month FCM Delivery Financial Assurance obligation, in each case without giving effect to the IMC and MCC variables when calculating such additional amount. Where the estimated monthly capacity payments for each Designated FCM Participant, shall be updated three (3) days after publication of the most recent FCM Preliminary Capacity Performance Score report (or equivalent report) on the Market Information Server.

DFAMW (delivery financial assurance MW) equals the sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. If the calculated DFAMW is less than zero, then the DFAMW will be set equal to zero.

PE (potential exposure) is a monthly value calculated for the Designated FCM Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. The Forward Capacity Auction Starting Price shall correspond to that used in the Forward Capacity Auction corresponding to the current Capacity Commitment Period and the capacity prices shall correspond to those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month.

In the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7 of Market Rule 1, the Forward

Capacity Auction Starting Price shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) in the above calculation until the multi-year election period expires.

ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. For the purpose of calculating the ABR, all Capacity Balancing Ratios, including Capacity Balancing Ratios for Capacity Scarcity Conditions that occurred in past Capacity Commitment Periods or in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, shall be calculated utilizing the Capacity Balancing Ratio formula that is currently effective, as described in Section III.13.7.2.3 or Section III.15.8.2.3 of Market Rule 1. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60.

CWAP (capacity weighted average performance) is the capacity weighted average performance of the Designated FCM Participant's portfolio. For each resource in the Designated FCM Participant's portfolio, excluding any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1, and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource's Capacity Supply Obligation shall be multiplied by the average performance of the resource. The CWAP shall be the sum of all such values, divided by the Designated FCM Participant's DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

The average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months

in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary average performance for gas-fired steam generating resources, combined-cycle combustion turbines and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating resources shall equal 0.85; the temporary average performance for oil-fired steam generating resources shall equal 0.65; the temporary average performance for all other resources shall equal 1.00. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

SF (scaling factor) is a month-specific multiplier, as follows:

June and December	2.000;
July and January	1.732;
August and February	1.414;
All other months	1.000.

Peak Monthly Stop-loss equals the largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

Second Largest Monthly Stop-loss equals the second largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

2. Corporate Liquidity Assessment Methodology

The ISO will perform a "Corporate Liquidity Assessment" to determine the appropriate liquidity risk assessment category for each Designated FCM Participant (i.e., low risk,

medium risk, or high risk) that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter.

(a) For each Designated FCM Participant, the Corporate Liquidity Assessment shall be performed as follows:
- When the Available Corporate Liquidity is greater than or equal to the sum of the three largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered low risk;
- When the Available Corporate Liquidity is less than the sum of the three largest but greater than or equal to the sum of the two largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered medium risk; and
- When the Available Corporate Liquidity is less than the sum of the two largest Applicable Monthly Stop-losses during the Calculation Period, the Designated FCM Participant shall be considered high risk.

(b) For Designated FCM Participants that have provided a guaranty (in accordance with this Section VII.A) from the same Affiliate, or for Designated FCM Participants that are also providing a guaranty (in accordance with this Section VII.A) for an Affiliate:
- The respective Designated FCM Participants will be assessed as a whole and will be collectively assigned one Corporate Liquidity Assessment result (i.e., low risk, medium risk, or high risk);
- When the Available Corporate Liquidity is greater than or equal to the sum of the three largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered low risk;
- When the Available Corporate Liquidity is less than the sum of the three largest aggregated Applicable Monthly Stop-losses but is greater than or equal to the sum of two largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered medium risk; and

- When the Available Corporate Liquidity is less than the sum of the two largest aggregated Applicable Monthly Stop-losses during the Calculation Period, each Designated FCM Participant in the collective assessment is considered high risk.

(c) For Designated FCM Participants that have provided a guaranty (in accordance with this Section VII.A) from multiple Affiliates:

- The guarantors' financial statements will be considered on an aggregate basis for purposes of the Available Corporate Liquidity calculation taking into account other guaranties provided by any such guarantor under this Section VII.A.

Where:

Calculation Period is the current delivery month through the following five consecutive months.

The Applicable Monthly Stop-loss equals the sum of the monthly stop-losses for each resource in a Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1 for the corresponding months within the Calculation Period.

Available Corporate Liquidity is the sum of unrestricted cash and cash equivalents; marketable securities and money market instruments; undrawn committed credit facilities not expiring within three months of the date of the applicable financial statements; and excess financial assurance. Other than with respect to excess financial assurance, such values shall be (a) as reflected on the most recent financial statements provided by the Designated FCM Participant, provided that such financial statements were provided for the most recently completed financial reporting period and compliant with the requirements of this Section VII.A, and (b) calculated in accordance with international accounting standards or generally accepted accounting principles in the United States at the time of determination consistently applied. Excess financial assurance shall be calculated as any financial assurance (in an acceptable form in accordance with Section X) provided by the Designated FCM Participant covering its FCM Delivery Financial Assurance obligations plus any financial assurance (in an acceptable form in accordance with Section X) provided by the Designated FCM Participant in excess of its total

Financial Assurance Obligations, each as reflected in the ISO's Financial Assurance Management (FAM) or equivalent system.

For the avoidance of doubt, the components of the Available Corporate Liquidity calculation that are derived from financial statements shall be based on the financial statements of the Designated FCM Participant unless it provides an Affiliate guaranty in compliance with this Section VII.A, in which case the values shall be based on the financial statements of the entity(ies) providing the guaranty. If an acceptable Affiliate guaranty is provided, stop-loss and excess financial assurance values will still be based on the Designated FCM Participant.

Each Designated FCM Participant shall submit to the ISO, on a quarterly basis, its (or its guarantor's, as applicable) audited or unaudited balance sheet or equivalent financial statements, which shall show sufficient detail for the ISO to assess the Designated FCM Participant's (or guarantor's, as applicable) Available Corporate Liquidity. Such financial information shall be accompanied by a certificate from a Senior Officer of the Designated FCM Participant (or guarantor as applicable) that provides the relevant financial information and certifies the accuracy of the attached financial statements. If an attestation was made by an independent accounting firm, then the certificate shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required. The ISO shall post a generally acceptable "clean" form of certificate on its website. Financial statements provided on a quarterly basis shall be submitted within 10 days of such statements becoming available and within 65 days after the end of the applicable fiscal quarter.

Designated FCM Participants that are assessed as medium risk or high risk may elect to provide financial statements on a monthly basis until such a time as they are subsequently assessed as a lower risk category (e.g., from high risk to medium risk, medium risk to low risk, or high risk to low risk); provided that such election shall be for a minimum period of six continuous months during which they are continuously assessed at a lower risk category. Financial statements submitted on a monthly basis are required to be provided to the ISO within 20 days after the end of the prior month and otherwise be provided in accordance with this Section VII.A.

A Designated FCM Participant may choose not to submit financial statements as described in this Section VII.A. If a Designated FCM Participant chooses not to submit financial statements as described in this Section VII.A or if such financial statements are not compliant with the requirements described in this Section VII.A, the ISO shall use a value of $0.00 for Available Corporate Liquidity values derived from financial statements until such time as compliant financial statements are provided.

The ISO shall review the information provided pursuant to this Section VII.A on a rolling basis and will calculate the Available Corporate Liquidity within a reasonable time period which shall not exceed 30 Business Days from the date of receipt.

3. FCM Affiliate Guaranties

For the purposes of the Corporate Liquidity Assessment, a Designated FCM Participant may provide an unconditional, irrevocable guaranty from an Affiliate to the ISO guaranteeing the payment of all Capacity Performance Payments owed by the Designated FCM Participant. Upon the ISO's acceptance of an Affiliate guaranty, the guarantor(s) must provide financial statements in accordance with this Section VII.A, and the Corporate Liquidity Assessment will be performed based on the financial information of the guarantor(s). The ISO will post a generally acceptable sample "clean" guaranty on its website, and all guaranties provided pursuant to this Section VII.A shall be in such form with only non-material changes (as determined by the ISO in its sole discretion). The ISO in its sole discretion may update the form guaranty from time to time. The ISO has the right to draw upon the guaranty in the event of a default under the ISO New England Billing Policy up to any amount owed for unpaid Capacity Performance Payments. At any time, the ISO may in its sole discretion provide notice to a Designated FCM Participant that it is choosing to reject or terminate its Affiliate guaranty because such guaranty presents unreasonable risk to the ISO or the New England Markets. In the case of a termination (or planned termination), upon the ISO providing such notice the guaranty shall not be considered for purposes of such Designated FCM Participant's Corporate Liquidity Assessment beginning at 8:30 a.m. on the next Business Day, provided that the ISO may, in its sole discretion, extend this period by up to twenty (20) Business Days. For the avoidance of doubt, notice from the ISO to the Designated FCM Participant that the guaranty its Affiliate provided is being terminated (or will be

terminated), does not constitute a termination notice under such guaranty and the ISO, in its sole discretion, may choose when to send the applicable termination notice under the terms of such guaranty.

In the ISO's sole discretion, a Designated FCM Participant may provide an unconditional, irrevocable guaranty from multiple Affiliates to the ISO guaranteeing the payment of all Capacity Performance Payments owed by the Designated FCM Participant, so long as such guaranty is otherwise in accordance with this Section VII.A and the guarantors have joint and several liability under such guaranty.

B. Non-Commercial Capacity

Notwithstanding any provision of this Section VII to the contrary, a Designated FCM Participant offering Non-Commercial Capacity for a Resource that elected existing Resource treatment for the Capacity Commitment Period beginning June 1, 2010 will not be subject to the provisions of this Section VII.B with respect to that Resource (other than financial assurance obligations relating to transfers of Capacity Supply Obligations).

1. FCM Deposit

A Designated FCM Participant offering Non-Commercial Capacity into any upcoming Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day after its qualification for such auction under Market Rule 1, an amount equal to $2/kW times the Non-Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant (the "FCM Deposit").

2. Non-Commercial Capacity in Forward Capacity Auctions

a. [Reserved for Future Use]

b. Non-Commercial Capacity Participating in Forward Capacity Auctions

A Designated FCM Participant offering Non-Commercial Capacity into the Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8

a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction an amount calculated according to the following formula:

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) – FCM Deposit

Where:
NCC = the amount of Qualified Capacity that the ISO has qualified for the Designated FCM Participant for the Forward Capacity Auction minus any Commercial Capacity

NCCFCA$ = the Net CONE associated with the Forward Capacity Auction for which the NCC has qualified (adjusted as described in Section III.13.2.4).

Multiplier = one if the auction occurs within 40 months of the commencement of the Capacity Commitment Period for which the NCC has qualified; two if the auction occurs within 28 months of the commencement of the Capacity Commitment Period for which the NCC has qualified; and three if the auction begins within 16 months of the commencement of the Capacity Commitment Period for which the NCC has qualified.

FCM Deposit = $2/kW times the Non Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant

Upon completion of the Forward Capacity Auction, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated according to the following formula:

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) + NCC Trading FA

Where:
NCC = the Capacity Supply Obligation awarded to the Designated FCM Participant in the Forward Capacity Auction minus any Commercial Capacity

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the thirteenth Forward Capacity Auction, NCCFCA$ = the Capacity Clearing Price from the first run of the auction-clearing process of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded. For Capacity Supply Obligations acquired in the fourteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCCFCA$ = the Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4).

Multiplier = one beginning at 8 a.m. (Eastern Time) on the first Business Day occurring within 40 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded; two beginning at 8 a.m. (Eastern Time) on the first Business Day occurring within 28 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded; and three beginning at 8 a.m. (Eastern Time) on the first Business Day occurring within 16 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded.

In the case of Non-Commercial Capacity that fails to become commercial by the commencement of the Capacity Commitment Period associated with the Forward Capacity Auction in which it was awarded a Capacity Supply Obligation, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated as follows: beginning at 8 a.m. (Eastern Time) on the first Business Day of the second month of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded, the Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall be four. The Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall increase by one every six months thereafter until the Non-Commercial Capacity becomes commercial or the Capacity Supply Obligation is terminated.

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the twelfth Forward Capacity Auction, NCC Trading FA = zero. For Capacity Supply Obligations acquired in the thirteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCC Trading FA shall be zero until the start of the

applicable Capacity Commitment Period, at which time NCC Trading FA shall be calculated as described below, except that in no case shall NCC Trading FA be less than zero:

(a) the total amount of NCC that has been shed (whether before or after the start of the Capacity Commitment Period) in any reconfiguration auctions or Capacity Supply Obligation Bilaterals or that is subject to a failure to cover charge pursuant to Section III.13.3.4(b) (but this total amount shall not be greater than NCC); multiplied by

(b) the difference between: (x) the weighted average price at which the Capacity Supply Obligation was acquired in the Forward Capacity Auction (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); and (y) the weighted average price or failure to cover charge rate at which the Capacity Supply Obligation was shed or assessed, as applicable, except that for monthly Capacity Supply Obligation Bilaterals, one of the following prices will be used:

(i) If the Designated FCM Participant does not certify to the ISO that it has not entered into any contract or other transaction with another party regarding the pricing of such Capacity Supply Obligation Bilateral (other than those to be settled by the ISO) that has the effect of deflating its NCC Trading FA, then the lower of: (1) the applicable monthly reconfiguration auction price, and (2) the Capacity Supply Obligation Bilateral price shall be used;

(ii) If the Designated FCM Participant provides the certification described in subsection (i) above, is the Capacity Transferring Resource, and is an Affiliate of the Capacity Acquiring Resource, then the lower of: (1) the Capacity Supply Obligation Bilateral price, and (2) the applicable Capacity Clearing Price (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs) shall be used; or

(iii) If neither subsection (i) nor (ii) applies, then the Capacity Supply Obligation Bilateral price shall be used.

plus

(c) the quantity of any Annual Reconfiguration Transactions associated with NCC for the relevant Capacity Commitment Period in which the Designated

FCM Participant is the Capacity Transferring Resource (but this amount shall not be greater than NCC) multiplied by the difference between: (x) the applicable annual reconfiguration auction clearing price, and (y) the transaction price, which shall equal one of the following:

(i) If the Designated FCM Participant does not certify to the ISO that it has not entered into any contract or other transaction with another party regarding the pricing of such Annual Reconfiguration Transaction (other than those to be settled by the ISO) that has the effect of deflating its NCC Trading FA, the transaction price shall be equal to the lower of: (1) the applicable annual reconfiguration auction clearing price, and (2) the applicable Annual Reconfiguration Transaction price;

(ii) If the Designated FCM Participant provides the certification described in subsection (i) above, is the Capacity Transferring Resource, and is an Affiliate of the Capacity Acquiring Resource, then the transaction price shall be equal to the lower of: (1) the applicable Annual Reconfiguration Transaction price, and (2) the applicable Capacity Clearing Price (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); or

(iii) If neither subsection (i) nor (ii) applies, then the applicable Annual Reconfiguration Transaction price shall be used.

c. Non-Commercial Capacity Deferral

Where the Commission approves a request to defer a Capacity Supply Obligation filed pursuant to Section III.13.3.7 of Market Rule 1, the Designated FCM Participant must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) 30 days after Commission approval of the request to defer, an amount equal to the amount that would apply to a resource that has not achieved commercial operation one year after the start of a Capacity Commitment Period in which it has a Capacity Supply Obligation, as calculated pursuant to Section VII.B.2.a or Section VII.B.2.b, as applicable.

3. Return of Non-Commercial Capacity Financial Assurance

Non-Commercial Capacity cleared in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction that is declared commercial and has had its capacity rating verified by the ISO or otherwise becomes a Resource meeting the definition of Commercial Capacity, or that is declared commercial and had a part of its capacity rating verified by the ISO and the applicable Designated FCM Participant indicates no additional portions of that Resource will become commercial, that portion of the Resource shall no longer be considered Non-Commercial Capacity under the ISO New England Financial Assurance Policy and will instead become subject to the provisions of the ISO New England Financial Assurance Policy relating to Commercial Capacity; provided that in either such case, the Designated FCM Participant will need to include in the calculation of its Financial Assurance Requirement an amount attributable to any remaining Non-Commercial Capacity.

Once Non-Commercial Capacity associated with a Capacity Supply Obligation awarded in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter becomes commercial, the Non-Commercial Capacity Financial Assurance Amount for any remaining Non-Commercial Capacity shall be recalculated according to the process outlined above for Non-Commercial Capacity participating in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter.

4. Credit Test Percentage Consequences for Provisional Members

If a Provisional Member is required to provide additional financial assurance under the ISO New England Financial Assurance Policy solely in connection with (A) a supply offer of Non-Commercial Capacity into any Forward Capacity Auction and (B) its obligation to pay Participant Expenses as a Provisional Member, and that Provisional Member is maintaining the amount of additional financial assurance required under the ISO New England Financial Assurance Policy, then the provisions of Section III.B of the ISO New England Financial Assurance Policy relating to the consequences of that Market Participant's Market Credit Test Percentage equaling 80 percent (80%) or 90 percent (90%) shall not apply to that Provisional Member.

C. SBE Financial Assurance

A Designated FCM Participant with System-Backed Export transactions, as defined in Section III.13.7.2.A and Section III.15.8.2.A of Market Rule 1, must include SBE Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy.

SBE Financial Assurance is calculated according to the following formula for a Designated FCM Participant with System-Backed Export transactions.

SBE Financial Assurance = (PPR * SBE MW * Scarcity Hours) – MEC – PMEC

Where:
PPR is the Performance Payment Rate as defined in Section III.13.7.2.5 and Section III.15.8.2.5 of Market Rule 1.

SBE MW equals the Designated FCM Participant's average MW of System-Backed Exports across all Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available; provided, however, that, beginning on October 1, 2026, data from Capacity Scarcity Conditions that occurred prior to October 1, 2026 shall no longer be used once data is available from a Capacity Scarcity Condition in the relevant group of months in a prior Capacity Commitment Period or a Capacity Scarcity Condition in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.

Scarcity Hours equals the highest total number of hours in which a Capacity Scarcity Condition occurred during any month within the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.

MEC (monthly export charges) equals System-Backed Export charges incurred in previous months, which have not yet been invoiced in instances where the MEC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MEC is a charge to the Designated FCM Participant. The MEC is estimated from the first day of the current month until it is replaced by the actual settled MEC value when settlement is complete.

PMEC (preliminary export charges) equals estimated System-Backed Export charges incurred in the current month. Where the estimated System-Backed Export charges shall be updated three (3) days after publication of the applicable report on the Market Information Server.

D. Loss of Capacity and Forfeiture of Non-Commercial Capacity Financial Assurance

If a Designated FCM Participant that has acquired Capacity Supply Obligations associated with Non-Commercial Capacity is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy and does not cure such default within the appropriate cure period, or if a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy during the period between the day that is three Business Days before the FCM Deposit is required and the first day of the Forward Capacity Auction and does not cure such default within the appropriate cure period, then: (i) beginning with the first Business Day following the end of such cure period that Designated FCM Participant will be assessed a default charge of one percent (1%) of its total Non-Commercial Capacity Financial Assurance Amount at that time for each Business Day that elapses until it cures its default; and (ii) if such default is not cured by 5:00 p.m. (Eastern Time) on the sooner of (x) the fifth Business Day following the end of such cure period or (y) the second Business Day prior to the start of the next scheduled Forward Capacity Auction or annual reconfiguration auction or annual Capacity Supply Obligation Bilateral submission (such period being referred to herein as the "Non-Commercial Capacity Cure Period"), then, in addition to the other actions described in this Section VII, (A) all Capacity Supply Obligations associated with Non-Commercial Capacity that were awarded to the defaulting Designated FCM Participant in previous Forward Capacity Auctions and reconfiguration auctions and that the defaulting Designated FCM Participant acquired by

entering into Capacity Supply Obligation Bilaterals shall be terminated; (B) the defaulting Designated FCM Participant shall be precluded from acquiring any Capacity Supply Obligation that would be associated with Non-Commercial Capacity for which the defaulting Designated FCM Participant has submitted an FCM Deposit; (C) the ISO will (1) draw down the entire amount of the FCM Deposit and the Non-Commercial Capacity Financial Assurance Amount associated with the terminated Capacity Supply Obligations and (2) issue an Invoice to the Designated FCM Participant if there is a shortfall resulting from that Designated FCM Participant's failure to maintain adequate financial assurance hereunder or if the Designated FCM Participant used a Market Credit Limit to meet its FCM Financial Assurance Requirements; and (D) the default charges described in clause (i) above shall not be assessed to that Designated FCM Participant. All default charges collected under clause (i) above will be deposited in the Late Payment Account in accordance with the ISO New England Billing Policy.

If a Designated FCM Participant's Capacity Supply Obligation is terminated under Market Rule 1, the ISO will draw down the entire Non-Commercial Capacity Financial Assurance Amount provided by such Designated FCM Participant with respect to such terminated Capacity Supply Obligation. If the Designated FCM Participant has not provided enough financial assurance to cover the amount due (or that would have been due but for the Designated FCM Participant's positive Market Credit Limit) with respect to such Non-Commercial Capacity Financial Assurance Amount, then the ISO will issue an Invoice to the Designated FCM Participant for the amount due.

E. Composite FCM Transactions

For separate resources that seek to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide that capacity (collectively, a "Composite FCM Transaction"), each Designated FCM Participant participating in that Composite FCM Transaction will be responsible for providing the financial assurance required as follows:

1. the FCM Financial Assurance Requirements for each Designated FCM Participant shall be determined solely with respect to the capacity being provided, or sought to be provided, by that Designated FCM Participant;

2. [reserved];

3. if the Composite FCM Transaction involves one or more Resources seeking to provide or providing Non-Commercial Capacity, the Non-Commercial Capacity Financial Assurance Amount under Section VII.B for each Designated FCM Participant with respect to that Composite FCM Transaction will be calculated based on the commercial status of the Non-Commercial Capacity cleared through the Forward Capacity Auction;

4. any Non-Commercial Capacity Financial Assurance Amount provided under Section VII.B by each Designated FCM Participant with respect to each Resource providing Non-Commercial Capacity in the Composite FCM Transaction will be recalculated according to Section VII.B.3 as the corresponding Resource becomes commercial; and

5. in the event that the Capacity Supply Obligation is terminated, Section VII.D shall apply only to the Non-Commercial Capacity of the Designated FCM Participant participating in the Composite FCM Transaction that has failed to satisfy its obligations, and any Invoice issued thereunder will be issued only to that Designated FCM Participant.

6. the FCM Delivery Financial Assurance calculated under Section VII.A for each Designated FCM Participant contributing resources to a Composite FCM Transaction shall be based on the Capacity Supply Obligation that is provided by that Designated FCM Participant in the current month of the Capacity Commitment Period, provided that the FCM charges incurred in previous months, but not yet paid, shall increase the FCM Financial Assurance Requirements only of the Designated FCM Participant that incurred the charges.

F. Transfer of Capacity Supply Obligations

1. Transfer of Capacity Supply Obligations in Reconfiguration Auctions

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a reconfiguration auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of bidding in that reconfiguration auction, the amounts described in subsections (a) and (b) below.

(a) For the 12 month period beginning with the current month, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For purposes of this subsection (a), months in this period in which that Designated FCM Participant's net FCM revenue results in a credit are disregarded (i.e., the net credits from such months are not used to reduce the amount described in this subsection (a)) and the current month FCM charges are prorated to the proportion of remaining days in the month. The amount described in this subsection (a), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

(b) For the period including each month that is after the period described in subsection (a) above and that is included in a Capacity Commitment Period for which a Forward Capacity Auction has been conducted, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For this period, the sum of such charges may be offset by net credits from months in which the net FCM revenue results in a credit, but in no case will the amount described in this subsection (b) be less than zero. The amount described in this subsection (b), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

For purposes of these calculations, the net FCM revenue for a month shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations, demand bids and Annual Reconfiguration Transactions in the Forward Capacity Market, exclusive of any accrued Capacity Performance Payments on positions currently or previously held. Upon the completion of each reconfiguration auction, the amount to be included in the calculation of any FCM Financial Assurance Requirements of that Designated FCM Participant shall be adjusted to reflect the cleared quantities at the zonal clearing price for all activity in that reconfiguration auction and accepted Annual Reconfiguration Transactions.

2. Transfer of Capacity Supply Obligations in Capacity Supply Obligation Bilaterals

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a Capacity Supply Obligation Bilateral must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Capacity Supply Obligation Bilateral,

amounts calculated as described in Section VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Capacity Supply Obligation Bilaterals, all of those transactions will be rejected. If the Designated FCM Participant's request to transfer a Capacity Supply Obligation in a Capacity Supply Obligation Bilateral is not accepted, it will no longer include amounts related to that Capacity Supply Obligation in the calculation of its FCM Financial Assurance Requirements.

3. Financial Assurance for Annual Reconfiguration Transactions

A Designated FCM Participant that submits an Annual Reconfiguration Transaction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Annual Reconfiguration Transaction, amounts calculated as described in Section VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Annual Reconfiguration Transactions, all of those transactions will be rejected. If a transaction is rejected, the Designated FCM Participant is no longer required to include amounts related to that transaction in the calculation of its FCM Financial Assurance Requirements.

4. Substitution Auctions

A Designated FCM Participant that participates in a substitution auction must include the following charges and credits in its FCM Financial Assurance Requirements.

a. For any supply offer with at least one price-quantity pair priced less than zero must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing any price-quantity pairs priced less than zero for each month of the Capacity Commitment Period associated with the Forward Capacity Auction shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

b. A Designated FCM Participant (i) that submits a demand bid into a substitution auction for a resource that is subject to a multi-year rate pursuant to Section III.13.1.3.5.4 or Section III.13.1.1.2.2.4, (ii) for which the maximum charge that would result from clearing the capacity subject to the multi-year rate election would exceed the revenue the Designated FCM Participant will receive for the relevant Capacity Commitment Period under its multi-year rate election for the resource, (iii) must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing the capacity subject to the multi-year rate election shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

c. If a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction and does not cure such default by the earlier of (i) the end of the appropriate cure period and (ii) 5 p.m. (Eastern Time) on the second Business Day prior to the start of the Forward Capacity Auction, then the defaulting Designated FCM Participant shall be precluded from submitting a supply offer or demand bid that is subject to this Section VII.F.4.

d. Upon the completion of the substitution auction, the amount to be included in the calculation of the FCM Financial Assurance Requirements for a Designated FCM Participant as described in Section VII.F.1 above shall be adjusted to reflect all charges and credits related to the purchase or sale of Capacity Supply Obligations in the substitution auction.

VIII. [Reserved]

IX. THIRD-PARTY CREDIT PROTECTION

The ISO shall obtain third-party credit protection, in the form of credit insurance coverage ("Credit Coverage"), on terms acceptable to the ISO in its reasonable discretion at least in an amount covering

collectively the Credit Qualifying Rated Market Participants based on the formula below. Notwithstanding the foregoing, if the entity providing such Credit Coverage cannot provide the amount required by this Section IX, the ISO will reduce the required coverage for all Credit Qualifying Rated Market Participants on a pro rata basis. The total amount of the Credit Coverage shall be at least the aggregate of the following formula; provided, however, if the entity providing the Credit Coverage denies coverage (in whole or in part) for any Credit Qualifying Rated Market Participant based on its rights under the insurance policy, the ISO will use reasonable efforts to obtain documentation regarding the denial and will make reasonable efforts to appeal such denial. For each Credit Qualifying Rated Market Participant, the portion of the Credit Coverage shall be the lesser of: (A) the sum of (x) 2.5 times the average Hourly Charges for such Credit Qualifying Rated Market Participant within the previous fifty-two calendar weeks plus (y) 2.5 times the sum of the average Non-Hourly Charges (excluding charges or credits related to FTR transactions) and the average Transmission Charges for such Credit Qualifying Rated Market Participant within the previous twelve calendar months; or (B) $50 million. For any Credit Qualifying Rated Market Participant, the applicable amount of the Credit Coverage shall be adjusted monthly if the above formula produces a change that is either (A) 10% or greater, or (B) greater than $100,000. The Credit Coverage shall be provided by an insurance company rated "A-" or better by A.M. Best & Co. or "A" or better by S&P. The cost of the Credit Coverage obtained for each calendar year shall be allocated to all Credit Qualifying Rated Market Participants pro rata based, for each Credit Qualifying Rated Market Participant, on the average amount of the Invoices issued to that Credit Qualifying Rated Market Participant under the ISO New England Billing Policy in the preceding calendar year. Each Credit Qualifying Rated Market Participant shall provide the ISO with such information as may be reasonably necessary for the ISO to obtain the Credit Coverage at the lowest possible cost.

X. ACCEPTABLE FORMS OF FINANCIAL ASSURANCE

Provided that the requirements set forth herein are satisfied, acceptable forms of financial assurance include shares of registered or private mutual funds held in a shareholder account or a letter of credit, each in accordance with the provisions of this Section X. All costs associated with obtaining financial security and meeting the provisions of the ISO New England Financial Assurance Policy are the responsibility of the Market Participant or Non-Market Participant Transmission Customer providing that security (each a "Posting Entity").

A. Shares of Registered or Private Mutual Funds in a Shareholder Account

Shares of registered or private mutual funds in a shareholder account are an acceptable form of financial assurance provided that the Posting Entity providing such collateral (i)

completes all required documentation to open an account with the financial institution selected by the ISO, after consultation with the NEPOOL Budget and Finance Subcommittee, (ii) completes and executes a security agreement ("Security Agreement") in the form of Attachment 1 to the ISO New England Financial Assurance Policy (as may be modified pursuant to Section X.B.1) and is in compliance with the Security Agreement, and (iii) completes and executes a Control Agreement in the form posted on the ISO website (as may be modified pursuant to Section X.B.1) and is in compliance with the Control Agreement. Any material variation from the form of Security Agreement included in Attachment 1 to the ISO New England Financial Assurance Policy (other than as modified pursuant to Section X.B.1) or the form of Control Agreement (other than as modified pursuant to Section X.B.1) posted on the ISO website must be approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and, in the case of the Security Agreement, filed with the Commission. To the extent any amount of shares contained in the shareholder account is no longer required hereunder, the ISO shall return such collateral to the Posting Entity providing it within four (4) Business Days of a request to do so.

If the amount of collateral maintained in the shareholder account is below the required level (including by reason of losses on investments), the Posting Entity shall immediately replenish or increase the amount to the required level. The collateral will be held in an account maintained in the name of the Posting Entity and invested in the investment selected by that Posting Entity from a menu of investment options listed at the time on the ISO's website, which menu will be approved by the NEPOOL Budget and Finance Subcommittee, with discounts applied to the investments in certain of such options if and as determined by the NEPOOL Budget and Finance Subcommittee. If a Posting Entity does not select an investment for its collateral, that collateral will be invested in the "default" investment option selected by the ISO and approved by the NEPOOL Budget and Finance Subcommittee from time to time. Any dividends and distribution on such investment will accrue to the benefit of the Posting Entity. The ISO may sell or otherwise liquidate such investments at its discretion to meet the Posting Entity's obligations to the ISO. In no event will the ISO or NEPOOL or any NEPOOL Participant have any liability with respect to the investment of collateral under this Section X.A.

Notwithstanding the foregoing, an investment in shares of a registered fund in a shareholder account shall not be an acceptable form of financial assurance for a Posting Entity that is not a U.S. Person, as defined in Regulation S under the Securities Act of 1933, as amended, unless the financial institution selected by the ISO allows such Posting Entity to invest in the investment options listed at the time on the ISO's website or the Posting Entity is invested in the investment options listed on the ISO's website as of March 19, 2015.

B. Letter of Credit

An irrevocable standby letter of credit provides an acceptable form of financial assurance to the ISO. For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the end of the Business Day that is 30 days prior to the termination of such letter of credit. If the letter of credit amount is below the required level, the Posting Entity shall immediately replenish or increase the letter of credit amount or obtain a substitute letter of credit. The account party on a letter of credit must be either the Posting Entity whose obligations are secured by that letter of credit or an Affiliate of that Posting Entity.

1. Risk Mitigation Draws

The ISO may draw against a letter of credit for two reasons in addition to a failure to pay under the ISO New England Billing Policy: i) an expiring letter of credit has not been renewed, or ii) the issuing bank is downgraded below the minimum ratings requirement, each in accordance with the terms of the letter of credit (the "Risk Mitigation Draws"). The ISO may exercise its rights under the Risk Mitigation Draws up to the amount that a Posting Entity's financial assurance requirements are not covered by acceptable forms of financial assurance. The ISO will hold such funds as a security deposit for the satisfaction of all obligations owed to the ISO by the Posting Entity (the "Risk Mitigation Drawn Funds"). The Risk Mitigation Drawn Funds shall be considered an appropriate form of financial assurance as described in this Section X. The ISO will hold all right, title, and interest in the Risk Mitigation Drawn Funds and the Posting Entity shall have a contingent right to such funds less any amounts applied to any debts owed to the ISO (pursuant to the Tariff, including the ISO New England Billing Policy): (i) upon the termination of its Market Participant Financial Assurance Requirement in accordance with Section III of the Financial Assurance Policy, (ii) upon the Posting Entity's

provision of an alternative form of acceptable financial assurance in accordance with this Section X, or (iii) to the extent that any portion of the Risk Mitigation Drawn Funds are no longer required hereunder, upon the Posting Entity providing a written request to the ISO to return such portion of the funds (which request shall be honored within four (4) Business Days).

Upon request of the ISO, but no later than five (5) Business Days after the Risk Mitigation Draw, the Posting Entity shall execute a Security Agreement in the form of Attachment 1 to the ISO New England Financial Assurance Policy, provided that such form shall be modified to include within the definition of Collateral, funds received from a Risk Mitigation Draw, or an amendment to its existing Security Agreement in a form acceptable to the ISO in its sole discretion. Within thirty (30) days of the Risk Mitigation Draw the Posting Entity shall satisfy its obligations pursuant to the paragraph immediately below to direct the deposit of the Risk Mitigation Drawn Funds into the Posting Entity's shareholder account as described in Section X.A. Notwithstanding the prior sentence, if the Posting Entity provides written documentation to the ISO (which documentation must be to the ISO's reasonable satisfaction) of its inability to open a shareholder account as described in Section X.A, and the Posting Entity has executed a Security Agreement or an amendment to its existing Security Agreement as required above, the ISO shall continue to hold the Risk Mitigation Drawn Funds (and such amount shall continue to be considered financial assurance), subject to the Posting Entity's contingent right to such funds as described above, in a form determined by the ISO in its sole discretion, and any interest or income accrued on such funds, if applicable, shall be considered part of the Posting Entity's financial assurance.

Upon a Risk Mitigation Draw and unless the Posting Entity has either posted other appropriate financial assurance in the forms permitted by this Section X or provided written documentation of its inability to do so in accordance with the preceding paragraph, the Posting Entity shall within thirty (30) days of the Risk Mitigation Draw complete any steps required by the ISO to (a) open a shareholder account as described in Section X.A, (b) execute any necessary documentation, including any amendments to the Security Agreement and Control Agreement deemed necessary by the ISO in a form acceptable to the ISO in its sole discretion, for the ISO to deposit the Risk Mitigation Drawn Funds into the Posting Entity's shareholder account, and (c) direct the ISO to

deposit the Risk Mitigation Default Drawn Funds into that Posting Entity's shareholder account as described in Section X.A. Upon the Posting Entity's completion of the foregoing steps in (a) through (c) to the ISO's satisfaction, ISO shall deposit the Risk Mitigation Default Drawn Funds into that Posting Entity's shareholder account and the balance of the funds then on deposit in such account shall continue to be the collateral of the ISO.

The ISO may apply any funds received from a letter of credit, including the Risk Mitigation Drawn Funds held as a security deposit, to amounts owed by the Posting Entity in accordance with the ISO New England Billing Policy. If a Posting Entity fails to comply with the provisions of this Section X.B.1, then the Posting Entity will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

2. Requirements for Banks

Each bank issuing a letter of credit that serves as financial assurance must meet the requirements of this Section X.B.2. Each such bank must be on the ISO's "List of Eligible Letter of Credit Issuers" which shall be established pursuant to this Section X.B.2. The ISO will post the current List of Eligible Letter of Credit Issuers on its website, and update that List and posting no less frequently than quarterly; provided that if a change is made to the List of Eligible Letter of Credit Issuers, the ISO shall update the List and provide notice to the NEPOOL Budget & Finance Subcommittee. To be included on the List of Eligible Letter of Credit Issuers, (i) the bank must be organized under the laws of the United States or any state thereof, or be the United States branch of a foreign bank; (ii) have a minimum long-term debt rating (or, if the bank does not have a minimum long-term debt rating, than a minimum corporate rating) of "A-" by S&P, or "A3" by Moody's, or "A-" by Fitch; and (iii) be approved by the ISO in its sole discretion. In the event that a bank is rated by multiple Rating Agencies, if any applicable rating from the Rating Agencies falls below the levels listed, then a bank will not be considered to have satisfied the requirement under this paragraph. In addition, no Posting Entity may provide a letter of credit that has been issued by a bank that is an Affiliate of that Market Participant.

If a bank that is included on the List of Eligible Letter of Credit Issuers fails to satisfy the criteria set forth above or if the ISO determines in its sole discretion that despite satisfying the criteria set forth above, accepting a letter of credit from a bank on the List of Eligible Letter of Credit Issuers presents an unreasonable risk that a bank may fail to honor the terms of such letter of credit, the applicable Posting Entity will have five (5) Business Days from the date on which the ISO provides notice of such failure or removal to replace the letter of credit with a letter of credit from a bank satisfying the criteria or provide other financial assurance satisfying the requirements of the ISO New England Financial Assurance Policy. The ISO may extend that cure period to twenty (20) Business Days in its sole discretion. The ISO must promptly advise the NEPOOL Budget and Finance Subcommittee of any extension of a cure period beyond five (5) Business Days under this provision. For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the expiration of the five (5) or twenty (20) Business Day cure period, as applicable.

No letter of credit bank may issue letters of credit under the ISO New England Financial Assurance Policy in an amount exceeding either: (i) $100 million in the aggregate for any single Posting Entity; or (ii) $150 million in aggregate for a group of Posting Entities that are Affiliates. If a bank is removed from the List of Eligible Letter of Credit Issuers based on the ISO's determination that there is an unreasonable risk that a bank may fail to honor the terms of such letter of credit, the ISO in its sole discretion may reinstate eligibility, provided that the bank otherwise meets the conditions of this Section X.B.2.

The following provisions shall apply when a bank fails to honor the terms of one or more letters of credit issued by the bank in favor of the ISO: (i) if the bank fails to honor the terms of one letter of credit in a rolling seven hundred and thirty day period, then the ISO will issue a notice of such failure to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contracts for all Market Participants; (ii) if the bank fails to honor either the terms of one letter of credit twice or the terms of two letters of credit in a rolling seven hundred and thirty day period, then (A) the ISO shall issue a notice described in subsection (i) above, (B) the bank will no longer be eligible to issue letters of credit in favor of the ISO, (C) any letters of credit issued by such bank in favor of the ISO will not be renewed, and (D) any letters of credit

issued by such bank in favor of the ISO must be replaced with another acceptable form of financial assurance within five (5) Business Days from the date on which the ISO provides notice of such failure (the ISO may extend that cure period to twenty (20) Business Days in its sole discretion). For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the expiration of the five (5) or twenty (20) Business Day cure period, as applicable. Notwithstanding the foregoing, the ISO in its sole discretion may reinstate eligibility after not less than two years from the loss of eligibility, provided that the bank otherwise meets the conditions of this Section X.B.2.

3. Form of Letter of Credit

Attachment 2 provides a generally acceptable sample "clean" letter of credit, and all letters of credit provided by Posting Entities shall be in this form (with only minor, non-material changes), unless a variation therefrom is approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and filed with the Commission. Notwithstanding the foregoing, Posting Entities that have provided a letter of credit in a form that was previously acceptable (e.g., under a prior version of Attachment 2) shall not be required to resubmit such letter of credit until the earlier of (a) the amendment or expiration of such letter of credit, in which case Posting Entity shall be required to provide a letter of credit in the form of Attachment 2, or (b) September 1, 2026. Any letter of credit provided for a new Posting Entity, for the purpose of covering the Initial Market Participant Financial Assurance Requirement, must have a minimum term of 120 days. All costs incurred by the ISO in collecting on a letter of credit provided under the ISO New England Financial Assurance Policy shall be paid, or reimbursed to the ISO, by the Posting Entity providing that letter of credit.

C. Special Provisions for Provisional Members

Notwithstanding any other provision of the ISO New England Financial Assurance Policy to the contrary, due to the temporary nature of a Market Participant's status as a Provisional Member and the relatively small amounts due from Provisional Members, any Provisional Member required to provide additional financial assurance under the ISO New England Financial Assurance Policy may only satisfy the portion of that requirement attributable to Participant Expenses under the RNA by providing collateral maintained in a shareholder account in accordance with Section X.A. Provisional

Members will not have any other Non-Hourly Requirements under the ISO New England Financial Assurance Policy. If a Provisional Member uses a standing instruction to pay its Invoices pursuant to the ISO New England Billing Policy, in order to avoid a default and/or a Late Payment Charge, the total amount of collateral maintained in a shareholder account by that Provisional Member should be equal to the sum of (x) the Provisional Member's Financial Assurance Requirement under the ISO New England Financial Assurance Policy that is attributable to Participant Expenses under the RNA and (y) the amount due from that Provisional Member on its next Invoice under that ISO New England Billing Policy (not including the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Provisional Member). Provisional Members are also required to satisfy all other provisions of the ISO New England Financial Assurance Policy, and any additional financial assurance required to be provided by a Provisional Member that is not attributable to Participant Expenses may be satisfied by providing an acceptable form of financial assurance in accordance with this Section X. Without limiting or reducing in any way the requirements of the ISO New England Financial Assurance Policy that apply to a Provisional Member, the amount of collateral maintained in a shareholder account initially provided by a Provisional Member that is attributable to Participant Expenses (including any amounts provided in connection with the standing instruction under the ISO New England Billing Policy described above) shall be at least $2,500, and each Provisional Member will replenish that collateral maintained in a shareholder account to at least that $2,500 level on December 31 of each year.

XI. MISCELLANEOUS PROVISIONS

A. Obligation to Report Material Adverse Changes

Each Market Participant and each Non-Market Participant Transmission Customer is responsible for informing the ISO in writing within five (5) Business Days of any Material Adverse Change in its financial status. A "Material Adverse Change" in financial status includes, but is not limited to, the following: a downgrade to below an Investment Grade Rating by any Rating Agency; being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating; a bankruptcy filing or other insolvency; a report of a significant quarterly loss or decline of

earnings; the resignation of key officer(s); the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principals imposed by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; or a significant change in the Market Participant's or Non-Market Participant Transmission Customer's market capitalization. A Market Participant's or Non-Market Participant Transmission Customer's failure to timely disclose a Material Adverse Change in its financial status may result in termination proceedings by the ISO. If the ISO determines that there is a Material Adverse Change in the financial condition of a Market Participant- or Non-Market Participant Transmission Customer, then the ISO shall provide to that Market Participant or Non-Market Participant Transmission Customer a signed written notice two Business Days before taking any of the actions described below. The notice shall explain the reasons for the ISO's determination of the Material Adverse Change. After providing notice, the ISO may take one or more of the following actions: (i) require that, within two Business Days of receipt of the notice of Material Adverse Change, the Market Participant or Non-Market Participant Transmission Customer provide one of the forms of financial assurance described in Section X of the ISO New England Financial Assurance Policy and/or an additional amount of financial assurance in one of the forms of financial assurance described in Section X of the ISO New England Financial Assurance Policy; (ii) require that the Market Participant or Non-Market Participant Transmission Customer cease one or more transactions in the New England Markets; or (iii) require that the Market Participant or Non-Market Participant Transmission Customer take other measures to restore the ISO's confidence in its ability to safely transact in the New England Markets. Any additional amount of financial assurance required as a result of a Material Adverse Change shall be sufficient, as reasonably determined by the ISO, to cover the Market Participant's or Non-Market Participant Transmission Customer's potential settled and unsettled liability or obligation, provided, however, that if the additional amount of financial assurance required as a result of a Material Adverse Change is equal to or greater than $25 million, then the Chief Financial Officer shall first consult, to the extent practicable, with the ISO's Chief Executive Officer, Chief Operating Officer, and General Counsel. If the Market Participant or Non-Market Participant Transmission Customer fails to comply

with any of the requirements imposed as a result of a Material Adverse Change, then the ISO may initiate termination proceedings against the Market Participant or Non-Market Participant Transmission Customer.

B. Weekly Payments

A Market Participant or Non-Market Participant Transmission Customer may request that, in lieu of providing the entire amount of one of the financial assurances set forth above to satisfy its Financial Assurance Requirement, a weekly billing schedule be implemented for its Non-Hourly Charges and its Transmission Charges. The ISO may, in its discretion, agree to such a request; provided, however, that any weekly billing arrangement for Non-Hourly Charges and Transmission Charges will terminate no more than six (6) months after the date on which such arrangement begins unless the Market Participant or Non-Market Participant Transmission Customer requests an extension of such arrangement and demonstrates to the ISO's satisfaction in its sole discretion that the termination of such arrangement and compliance with the other provisions of the ISO New England Financial Assurance Policy (including providing the full amount of its Financial Assurance Requirement) will impose a substantial hardship on the Market Participant or Non-Market Participant Transmission Customer. Such demonstration of a substantial hardship shall be made every six (6) months after the initial demonstration, and a Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement for Non-Hourly Charges and Transmission Charges will be terminated if it fails to demonstrate to the ISO's satisfaction in its sole discretion at any such six (6) month interval that compliance with the other provisions of the ISO New England Financial Assurance Policy will impose a substantial hardship on it. If the ISO agrees to implement a weekly billing schedule for Non-Hourly Charges and Transmission Charges for a Market Participant or Non-Market Participant Transmission Customer, the Market Participant or Non-Market Participant Transmission Customer shall be billed weekly for such Non-Hourly Charges and Transmission Charges in accordance with the ISO New England Billing Policy. The Market Participant or Non-Market Participant Transmission Customer shall pay with respect to each weekly Invoice for Non-Hourly Charges and Transmission Charges an administrative fee, determined by the ISO, to reimburse the ISO for the costs it incurs as a result of that Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement.

If a weekly billing schedule is implemented for a Market Participant's or Non-Market Participant Transmission Customer's Non-Hourly Charges and Transmission Charges under this Section XI.B, the Market Participant or Non-Market Participant Transmission Customer may be required to provide the full amount of its Financial Assurance Requirement at any time if the Market Participant or Non-Market Participant Transmission Customer fails to pay when due any weekly Invoice. In addition, upon the termination of a Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement for Non-Hourly Charges and Transmission Charges, the Market Participant or Non-Market Participant Transmission Customer shall either satisfy the applicable rating requirements set forth herein, satisfy the Credit Threshold, or provide the full amount of one of the other forms of financial assurance set forth herein.

C. Use of Transaction Setoffs

In the event that a Market Participant or Non-Market Participant Transmission Customer has failed to satisfy its Financial Assurance Requirement hereunder, the ISO may retain payments due to such Market Participant or Non-Market Participant Transmission Customer, up to the amount of such Market Participant's or Non-Market Participant Transmission Customer's unsatisfied Financial Assurance Requirement, as a cash deposit securing such Market Participant's or Non-Market Participant Transmission Customer's obligations to the ISO, NEPOOL, the Market Participants, the PTOs and the Non-Market Participant Transmission Customers, provided, however, that a Market Participant or Non-Market Participant Transmission Customer will not be deemed to have satisfied its Financial Assurance Requirement under the ISO New England Financial Assurance Policy because the ISO is retaining amounts due to it hereunder unless such Market Participant or Non-Market Participant Transmission Customer has satisfied all of the requirements of Section X with respect to such amounts.

D. Reimbursement of Costs

Each Market Participant or Non-Market Participant Transmission Customer that fails to perform any of its obligations under the Tariff, including without limitation those arising under the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, shall reimburse the ISO, NEPOOL and each Market Participant, PTO and

Non-Market Participant Transmission Customer for all of the fees, costs and expenses that they incur as a result of such failure.

E. Notification of Default

In the event that a Market Participant or Non-Market Participant Transmission Customer fails to comply with the ISO New England Financial Assurance Policy (a "Financial Assurance Default"), such failure continues for at least two days and notice of that failure has not previously been given, the ISO may (but shall not be required to) notify such Market Participant or Non-Market Participant Transmission Customer in writing, electronically and by first class mail sent in each case to such Market Participant's or Non-Market Participant Transmission Customer's billing and credit contacts or such Market Participant's member or alternate member on the Participants Committee (it being understood that the ISO will use reasonable efforts to contact all three where applicable), of such Financial Assurance Default. Either simultaneously with the giving of the notice described in the preceding sentence or within two days thereafter (unless the Financial Assurance Default is cured during such period), the ISO shall notify each other member and alternate on the Participants Committee and each Market Participant's and Non-Market Participant Transmission Customer's billing and credit contacts of the identity of the Market Participant or Non-Market Participant Transmission Customer receiving such notice, whether such notice relates to a Financial Assurance Default, and the actions the ISO plans to take and/or has taken in response to such Financial Assurance Default. In addition to the notices provided for herein, the ISO will provide any additional information required under the ISO New England Information Policy.

F. Remedies Not Exclusive

No remedy for a Financial Assurance Default is or shall be deemed to be exclusive of any other available remedy or remedies. Each such remedy shall be distinct, separate and cumulative, shall not be deemed inconsistent with or in exclusion of any other available remedy, and shall be in addition to and separate and distinct from every other remedy. A Financial Assurance Default may result in suspension of the Market Participant or Non-Market Participant Transmission Customer or the commencement of termination proceedings by the ISO.

G. Inquiries and Contests

A Market Participant or Non-Market Participant Transmission Customer may request a written explanation of the ISO's determination of its Market Credit Limit, Transmission Credit Limit, Financial Assurance Requirement or Transmission Obligations, including any change thereto, by submitting that request in writing to the ISO's Credit Department, either by email at CreditDepartment@iso-ne.com or by facsimile at (413) 540-4569. That request must include the Market Participant's customer identification number, the name of the Market Participant or Non-Market Participant Transmission Customer and the specific information for which the Market Participant or Non-Market Participant Transmission Customer would like an explanation and must be submitted by the designated credit contact for that Market Participant or Non-Market Participant Transmission Customer as on file with the ISO. In addition, since Financial Assurance Requirements are updated at least daily, any request for an explanation relating to the calculation of, or a change in, a Financial Assurance Requirement must be submitted on the same day as that calculation or change. The ISO's response to any request under this Section XI.G shall include an explanation of how the applicable calculation or determination was performed using the formulas and criteria in the ISO New England Financial Assurance Policy. A Market Participant or Non-Market Participant Transmission Customer may contest any calculation or determination by the ISO under the ISO New England Financial Assurance Policy using the dispute resolution provisions of Section I.6 of the Tariff.

H. Forward Contract/Swap Agreement

All FTR transactions constitute "forward contracts" and/or "swap agreements" within the meaning of the United States Bankruptcy Code (the "Bankruptcy Code"), and the ISO shall be deemed to be a "forward contract merchant" and/or "swap participant" within the meaning of the Bankruptcy Code for purposes of those FTR transactions. Pursuant to the ISO New England Financial Assurance Policy, the ISO Tariff and the Market Participant Service Agreement with each Market Participant, the ISO already has, and shall continue to have, the following rights (among other rights) in respect of a Market Participant default under those documents (including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy): A) the right to terminate and/or liquidate any FTR transaction held by that Market Participant; B) the right to immediately proceed against any additional financial assurance provided by that Market Participant; C) the right to set off any obligations due and owing to that Market

Participant pursuant to any forward contract, swap agreement or similar agreement against any amounts due and owing by that Market Participant pursuant to any forward contract, swap agreement or similar agreement, such arrangement to constitute a "master netting agreement" within the meaning of the Bankruptcy Code; and D) the right to suspend that Market Participant from entering into future transactions in the FTR system. For the avoidance of doubt, upon the commencement of a voluntary or involuntary proceeding for a Market Participant under the Bankruptcy Code, and without limiting any other rights of the ISO or obligations of any Market Participant under the Tariff (including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy) or any Market Participant Service Agreement, the ISO may exercise any of its rights against such Market Participant, including, without limitation 1) the right to terminate and/or liquidate any FTR transaction held by that Market Participant, 2) the right to immediately proceed against any additional financial assurance provided by that Market Participant, 3) the right to set off any obligations due and owing to that Market Participant pursuant to any forward contract, swap agreement and/or master netting agreement against any amounts due and owing by that Market Participant with respect to an FTR transaction including as a result of the actions taken by the ISO pursuant to 1) above, and 4) the right to suspend that Market Participant from entering into future transactions in the FTR system.

ATTACHMENT 1

SECURITY AGREEMENT

THIS SECURITY AGREEMENT (the "Security Agreement") is effective as of this [__] day of [_____], 20[_], by and between [INSERT NAME], a [_____], having its principal office and place of business at [_____] (the "Debtor"), and ISO New England Inc., a Delaware nonprofit corporation (the "Secured Party" and collectively with the Debtor, the "Parties").

WITNESSETH:

In consideration of the mutual promises and covenants herein contained, the Parties agree as follows:

1. Definitions.

a. In this Security Agreement:

i. "Code" shall mean the Uniform Commercial Code, as enacted in the State of Connecticut and as amended from time to time.

ii. "Collateral" shall mean (a) all cash provided, submitted, wired or otherwise transferred or deposited by the Debtor to or with the Secured Party or a financial institution, investment firm, or other designee selected by the Secured Party or acting on the Secured Party's behalf, to hold or invest such cash deposit, from time to time in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (b) all securities or other investment property (as defined in the Code) of the Debtor, whether or not purchased with such cash deposit, submitted, wired or otherwise transferred, deposited or maintained by the Debtor to or with the Secured Party or its designee, in each case in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (c) all other property of Debtor submitted, pledged, assigned or otherwise transferred by the Debtor to the Secured Party or its designee, in each case, in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; and (d) the products and proceeds of each of the foregoing.

iii. "ISO Financial Assurance Policy" shall mean the Financial Assurance Policy in the Tariff, as amended, supplemented or restated from time to time, including but not limited to the Financial Assurance Policy in Exhibit 1A to Section I of the Tariff.

iv. "Tariff" shall mean the ISO New England Inc. Transmission, Markets and Services Tariff, as filed with the Federal Energy Regulatory Commission, as amended, supplemented and/or restated from time to time.

v. "Obligations" shall mean any and all amounts due from Debtor from time to time under the Tariff.

vi. "Market Participants" shall have the meaning set forth in the Tariff.

b. Any capitalized term not defined herein that is defined in the Code shall have the meaning as defined in the Code.

2. Security Interest. To secure the payment of all Obligations of the Debtor, Debtor hereby grants and conveys to the Secured Party a security interest in the Collateral. The Debtor hereby irrevocably authorizes the Secured Party at any time and from time to time to file in any applicable filing office any initial financing statements and amendments thereto that provide any information required by part 5 of Article 9 of the Code for the sufficiency or filing office acceptance of any financing statement or amendment.

3. Debtor's Covenants. The Debtor warrants, covenants and agrees with the Secured Party as follows:

a. The Debtor shall perform all of the Debtor's obligations under this Security Agreement according to its terms.

b. The Debtor shall defend the title to the Collateral against any and all persons and against all claims.

c. The Debtor shall at any time and from time to time take such steps as the Secured Party may reasonably request to ensure the continued perfection and priority of the Secured Party's security interest in the Collateral and the preservation of its rights therein.

d. The Debtor acknowledges and agrees that this Security Agreement grants, and is intended to grant, a security interest in the Collateral. If the Debtor is a corporation, limited liability company, limited partnership or other Registered Organization (as that term is defined in Article 9 of the Uniform Commercial Code as in effect in Connecticut) the Debtor shall, at its expense, furnish to Secured Party a certified copy of Debtor's organization documents verifying its correct legal name or, at Secured Party's election, shall permit the Secured Party to obtain such certified copy at Debtor's expense. From

time to time at Secured Party's election, the Secured Party may obtain a certified copy of Debtor's organization documents and a search of such Uniform Commercial Code filing offices, as it shall deem appropriate, at Debtor's expense, to verify Debtor's compliance with the terms of this Security Agreement.

e. The Debtor authorizes the Secured Party, if the Debtor fails to do so, to do all things required of the Debtor herein and charge all expenses incurred by the Secured Party to the Debtor together with interest thereon, which expenses and interest will be added to the Obligations.

4. Debtor's Representations and Warranties. The Debtor represents and warrants to the Secured Party as follows:

a. The exact legal name of the Debtor is as first stated above.

b. Except for the security interest of the Secured Party, Debtor is the owner of the Collateral free and clear of any encumbrance of any nature.

5. Non-Waiver. Waiver of or acquiescence in any default by the Debtor or failure of the Secured Party to insist upon strict performance by the Debtor of any warranties, covenants, or agreements in this Security Agreement shall not constitute a waiver of any subsequent or other default or failure. No failure to exercise or delay in exercising any right, power or remedy of the Secured Party under this Security Agreement shall operate as a waiver thereof, nor shall any partial exercise of any right, power or remedy preclude any other or further exercise thereof or the exercise of any other right, power or remedy. The failure of the Secured Party to insist upon the strict observance or performance of any provision of this Security Agreement shall not be construed as a waiver or relinquishment of such provision. The rights and remedies provided herein are cumulative and not exclusive of any other rights or remedies provided at law or in equity.

6. Events of Default. Any one of the following shall constitute an "Event of Default" hereunder by the Debtor:

a. Failure by the Debtor to comply with or perform any provision of this Security Agreement or to pay any Obligation; or

b. Any representation or warranty made or given by the Debtor in connection with this Security Agreement proves to be false or misleading in any material respect; or

c. Any part of the Collateral is attached, seized, subjected to a writ or distress warrant, or is levied upon, or comes within the possession of any receiver, trustee, custodian or assignee for the benefit of creditors.

7. Remedy upon the Occurrence of an Event of Default. Upon the occurrence of any Event of Default the Secured Party shall, immediately and without notice, be entitled to use, sell, or otherwise liquidate the Collateral to pay all Obligations owed by the Debtor.

8. Attorneys' Fees, etc. Upon the occurrence of any Event of Default, the Secured Party's reasonable attorneys' fees and the legal and other expenses for pursuing, receiving, taking, keeping, selling, and liquidating the Collateral and enforcing the Security Agreement shall be chargeable to the Debtor.

9. Other Rights.

a. In addition to all rights and remedies herein and otherwise available at law or in equity, upon the occurrence of an Event of Default, the Secured Party shall have such other rights and remedies as are set forth in the Tariff and ISO Financial Assurance Policy.

b. Notwithstanding the provisions of the ISO New England Information Policy, as amended, supplemented or restated from time to time (the "ISO New England Information Policy"), Debtor hereby (i) authorizes the Secured Party to disclose any information concerning Debtor to any court, agency or entity which is necessary or desirable, in the sole discretion of the Secured Party, to establish, maintain, perfect or secure the Secured Party's rights and interest in the Collateral (the "Debtor Information"); and (ii) waives any rights it may have under the ISO New England Information Policy to prevent, impair or limit the Secured Party from disclosing such information concerning the Debtor.

10. PRE-JUDGMENT REMEDY. DEBTOR ACKNOWLEDGES THAT THIS SECURITY AGREEMENT AND THE UNDERLYING TRANSACTIONS GIVING RISE HERETO CONSTITUTE COMMERCIAL BUSINESS TRANSACTED WITHIN THE STATE OF CONNECTICUT. IN THE EVENT OF ANY LEGAL ACTION BETWEEN DEBTOR AND

THE SECURED PARTY HEREUNDER, DEBTOR HEREBY EXPRESSLY WAIVES ANY RIGHTS WITH REGARD TO NOTICE, PRIOR HEARING AND ANY OTHER RIGHTS IT MAY HAVE UNDER THE CONNECTICUT GENERAL STATUTES, CHAPTER 903a, AS NOW CONSTITUTED OR HEREAFTER AMENDED, OR OTHER STATUTE OR STATUTES, STATE OR FEDERAL, AFFECTING PREJUDGMENT REMEDIES, AND THE SECURED PARTY MAY INVOKE ANY PREJUDGMENT REMEDY AVAILABLE TO IT, INCLUDING, BUT NOT LIMITED TO, GARNISHMENT, ATTACHMENT, FOREIGN ATTACHMENT AND REPLEVIN, WITH RESPECT TO ANY TANGIBLE OR INTANGIBLE PROPERTY (WHETHER REAL OR PERSONAL) OF DEBTOR TO ENFORCE THE PROVISIONS OF THIS SECURITY AGREEMENT, WITHOUT GIVING DEBTOR ANY NOTICE OR OPPORTUNITY FOR A HEARING.

11. WAIVER OF JURY TRIAL. THE DEBTOR AND THE SECURED PARTY HEREBY EACH KNOWINGLY, VOLUNTARILY AND IRREVOCABLY WAIVES THE RIGHT TO TRIAL BY JURY IN ANY ACTION, DEFENSE, COUNTERCLAIM, CROSSCLAIM AND/OR ANY FORM OF PROCEEDING BROUGHT IN CONNECTION WITH THIS SECURITY AGREEMENT OR RELATING TO ANY OBLIGATIONS SECURED HEREBY.

12. Additional Waivers. Demand, presentment, protest and notice of nonpayment are hereby waived by Debtor. Debtor also waives the benefit of all valuation, appraisement and exemption laws.

13. Binding Effect. The terms, warranties and agreements herein contained shall bind and inure to the benefit of the respective Parties hereto, and their respective legal representatives, successors and assigns.

14. Assignment. The Secured Party may, upon notice to the Debtor, assign without limitation its security interest in the Collateral.

15. Amendment. This Security Agreement may not be altered or amended except by an agreement in writing signed by the Parties.

16. Term.

a. This Security Agreement shall continue in full force and effect until all Obligations owed by the Debtor have been paid in full.

b. No termination of this Security Agreement shall in any way affect or impair the rights and liabilities of the Parties hereto relating to any transaction or events prior to such termination date, or to the Collateral in which the Secured Party has a security interest, and all agreements, warranties and representations of the Debtor shall survive such termination.

17. Choice of Law. The laws of the State of Connecticut shall govern the rights and duties of the Parties herein contained without giving effect to any conflict-of-law principles.

IN WITNESS WHEREOF, the Parties have signed and sealed this Security Agreement as of the day and year first above written.

[INSERT NAME]

By: _____

Name:

Title:

ISO NEW ENGLAND INC.

By:_____

Name:

Title:

ATTACHMENT 2

SAMPLE STANDBY LETTER OF CREDIT

[DATE PROVIDED]

IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT NO.

[EXPIRATION DATE]

WE DO HEREBY ISSUE THIS IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT BY ORDER OF AND FOR THE ACCOUNT OF [POSTING ENTITY OR AFFILIATE OF POSTING ENTITY ON BEHALF OF POSTING ENTITY] ("ACCOUNT PARTY") IN FAVOR OF ISO NEW ENGLAND INC. ("ISO" OR "BENEFICIARY") ("STANDBY LETTER OF CREDIT").

THIS STANDBY LETTER OF CREDIT IS IRREVOCABLE AND IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS AND BONA FIDE HOLDERS OF THIS STANDBY LETTER OF CREDIT THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT WILL BE HONORED ON PRESENTATION OF THIS STANDBY LETTER OF CREDIT.

THIS STANDBY LETTER OF CREDIT IS AVAILABLE IN ONE OR MORE DRAFTS AND MAY BE DRAWN HEREUNDER FOR THE ACCOUNT OF THE ACCOUNT PARTY UP TO AN AMOUNT NOT EXCEEDING US$ _____.00 (UNITED STATES DOLLARS _____ AND 00/100) .

THIS STANDBY LETTER OF CREDIT IS DRAWN AGAINST BY PRESENTATION TO US AT OUR OFFICE LOCATED AT THE FOLLOWING ADDRESS:

_____

_____

_____;

OF A DRAFT IN THE FORM OF A DRAWING CERTIFICATE THAT IS SIGNED BY A PURPORTED OFFICER OR AUTHORIZED AGENT OF THE ISO AND DATED THE DATE OF

PRESENTATION CONTAINING THE FOLLOWING STATEMENT IN (1) BELOW ALONG WITH THE APPROPRIATE STATEMENT IN (2) BELOW:

(1) "THE UNDERSIGNED HEREBY CERTIFIES TO [BANK] ("ISSUER"), WITH REFERENCE TO IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT NO. [------] (THE "STANDBY LETTER OF CREDIT") ISSUED BY ISSUER IN FAVOR OF ISO NEW ENGLAND INC. ("ISO"), THAT

(2) [POSTING ENTITY] HAS FAILED TO PAY THE ISO, IN ACCORDANCE WITH THE TERMS AND PROVISIONS OF THE TARIFF FILED BY THE ISO, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____.];**OR**

[ISSUER HAS FAILED TO MAINTAIN A MINIMUM LONG-TERM DEBT RATING FROM ANY APPLICABLE RATING AGENCY (OR, IF THE ISSUER DOES NOT HAVE A MINIMUM LONG-TERM DEBT RATING, THEN A MINIMUM CORPORATE RATING) OF "A-" BY STANDARD AND POOR'S , OR "A3" BY MOODY'S OR "A-" BY FITCH, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____. **]; OR**

[**INCLUDE ONLY IN FORM IF LETTER OF CREDIT HAS A FIXED EXPIRATION DATE:]** [AS OF THE CLOSE OF BUSINESS ON _____, 20__ (FILL IN DATE WHICH IS WITHIN 30 DAYS BEFORE THE EXPIRATION DATE OF THE STANDBY LETTER OF CREDIT), [ACCOUNT PARTY] HAS FAILED TO RENEW THE STANDBY LETTER OF CREDIT IN A MANNER ACCEPTABLE TO THE ISO, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____. **]; OR**

[**INCLUDE ONLY IN FORM IF LETTER OF CREDIT HAS AUTOMATIC RENEWAL LANGUAGE:]** [AS OF THE CLOSE OF BUSINESS ON _____, 20__ (FILL IN DATE WHICH IS WITHIN 30 DAYS BEFORE THE EXPIRATION DATE OF THE STANDBY LETTER OF CREDIT IF NOT AUTORENEWING), WE HAVE BEEN PROVIDED NOTICE FROM [ACCOUNT PARTY] [ISSUER] THAT THE STANDBY LETTER OF CREDIT WILL NOT BE

EXTENDED FOR AN ADDITIONAL ONE (1) YEAR PERIOD, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_____.]

IF PRESENTATION OF ANY DRAWING CERTIFICATE IS MADE ON A BUSINESS DAY AND SUCH PRESENTATION IS MADE AT OUR COUNTERS ON OR BEFORE 10:00 A.M. _____ TIME, WE SHALL SATISFY SUCH DRAWING REQUEST ON THE SAME BUSINESS DAY. IF THE DRAWING CERTIFICATE IS RECEIVED AT OUR COUNTERS AFTER 10:00 A.M. _____ TIME, WE WILL SATISFY SUCH DRAWING REQUEST ON THE NEXT BUSINESS DAY. FOR THE PURPOSES OF THIS SECTION, A BUSINESS DAY MEANS A DAY, OTHER THAN A SATURDAY OR SUNDAY, ON WHICH THE FEDERAL RESERVE BANK OF NEW YORK IS NOT AUTHORIZED OR REQUIRED TO BE CLOSED. DISBURSEMENTS SHALL BE IN ACCORDANCE WITH THE INSTRUCTIONS OF THE ISO.

THE FOLLOWING TERMS AND CONDITIONS APPLY:

THIS STANDBY LETTER OF CREDIT SHALL EXPIRE AT THE CLOSE OF BUSINESS [DATE] [AT LEAST 120 DAYS AFTER ISSUANCE FOR NEW POSTING ENTITIES].

[**INCLUDE ONLY IF LETTER OF CREDIT HAS A FIXED EXPIRATION DATE:]** [IF [ACCOUNT PARTY] HAS FAILED TO RENEW THIS STANDBY LETTER OF CREDIT IN A MANNER ACCEPTABLE TO THE ISO, YOU MAY DRAW ON THIS STANDBY LETTER OF CREDIT WITHIN THE THIRTY (30) DAYS PRIOR TO THE EXPIRY DATE BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.]

[**INCLUDE ONLY IF LETTER OF CREDIT IS TO HAVE AUTOMATIC RENEWAL LANGUAGE:]** [IT IS A CONDITION OF THIS STANDBY LETTER OF CREDIT THAT IT WILL BE AUTOMATICALLY EXTENDED WITHOUT AN AMENDMENT FOR A (1) YEAR PERIOD BEGINNING ON THE INITIAL EXPIRATION DATE HEREOF AND UPON EACH ANNIVERSARY OF SUCH DATE, UNLESS AT LEAST [THIRTY (30) **OR** SIXTY (60) **OR** NINETY (90)] DAYS PRIOR TO ANY SUCH EXPIRATION DATE WE HAVE SENT YOU, OR THE ACCOUNT PARTY HAS SENT YOU, WRITTEN NOTICE BY

REGULAR AND REGISTERED MAIL OR COURIER SERVICE THAT WE OR THE ACCOUNT PARTY ELECT NOT TO PERMIT THIS LETTER OF CREDIT TO BE SO EXTENDED, AND THAT THIS LETTER OF CREDIT WILL EXPIRE ON ITS THEN CURRENT EXPIRATION DATE. UPON RECEIPT OF SUCH NOTICE, YOU MAY DRAW ON THIS STANDBY LETTER OF CREDIT WITHIN THE THIRTY (30) DAYS PRIOR TO THE THEN RELEVANT EXPIRY DATE BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.]

IT IS A CONDITION OF THIS STANDBY LETTER OF CREDIT THAT WE SHALL MAINTAIN A MINIMUM LONG-TERM DEBT RATING (OR, IF WE DO NOT HAVE A MINIMUM LONG-TERM DEBT RATING, THEN A MINIMUM CORPORATE RATING) OF "A-" BY STANDARD AND POOR'S, OR "A3" BY MOODY'S OR "A-" BY FITCH. IN THE EVENT THAT WE ARE RATED BY MULTIPLE RATING AGENCIES, IF ANY APPLICABLE RATING FROM THE RATING AGENCIES FALLS BELOW THE LEVELS LISTED, THEN WE SHALL NOT BE CONSIDERED TO HAVE SATISFIED THIS CONDITION. IN THE EVENT THAT WE DO NOT SATISFY THE CONDITION REQUIRED BY THIS PARAGRAPH, YOU MAY DEMAND PAYMENT FROM US AT THE ADDRESS ABOVE, BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.

THE AMOUNT WHICH MAY BE DRAWN BY YOU UNDER THIS STANDBY LETTER OF CREDIT SHALL BE AUTOMATICALLY REDUCED BY THE AMOUNT OF ANY DRAWINGS HEREUNDER AT OUR COUNTERS. ANY NUMBER OF PARTIAL DRAWINGS ARE PERMITTED FROM TIME TO TIME HEREUNDER.

ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY.

THIS STANDBY LETTER OF CREDIT IS NOT TRANSFERABLE OR ASSIGNABLE. THIS STANDBY LETTER OF CREDIT DOES NOT INCORPORATE AND SHALL NOT BE DEEMED MODIFIED, AMENDED OR AMPLIFIED BY REFERENCE TO ANY DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE ISP, AS DEFINED BELOW) OR (B) IN WHICH THIS STANDBY

LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS STANDBY LETTER OF CREDIT RELATES.

THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE INTERNATIONAL STANDBY PRACTICES ("ISP98") OF THE INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NO. 590, INCLUDING ANY AMENDMENTS, MODIFICATIONS, OR REVISIONS THEREOF (THE "ISP"), EXCEPT TO THE EXTENT THAT THE TERMS HEREOF ARE INCONSISTENT WITH THE PROVISIONS OF THE ISP, IN WHICH CASE THE TERMS OF THIS STANDBY LETTER OF CREDIT SHALL GOVERN. THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY THE INTERNAL LAWS OF THE COMMONWEALTH OF MASSACHUSETTS TO THE EXTENT THAT THE TERMS ARE NOT GOVERNED BY THE ISP.

THIS STANDBY LETTER OF CREDIT MAY NOT BE AMENDED, CHANGED OR MODIFIED WITHOUT THE EXPRESS WRITTEN CONSENT OF THE ISO AND ISSUER.

WE HEREBY ENGAGE WITH YOU THAT DOCUMENTS DRAWN UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT SHALL BE DULY HONORED UPON PRESENTATION AS SPECIFIED AND WE REPRESENT THAT THE ACCOUNT PARTY IS NOT AN AFFILIATE OF THE ISSUER.

PRESENTATION OF ANY DRAWING CERTIFICATE UNDER THIS STANDBY LETTER OF CREDIT MAY BE SENT TO US BY COURIER, CERTIFIED MAIL, REGISTERED MAIL, OR FACSIMILE (WITH A CONFIRMING COPY OF SUCH FACSIMILE SENT AFTER THE DRAWING BY CERTIFIED MAIL TO THE ADDRESS SET FORTH BELOW; PROVIDED HOWEVER, THAT THE CONFIRMING COPY SHALL NOT BE A PREREQUISITE FOR US TO HONOR ANY PRESENTATION OTHERWISE MADE IN ACCORDANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT), OR SUCH OTHER ADDRESS AS MAY HEREAFTER BE FURNISHED BY US. OTHER NOTICES CONCERNING THIS STANDBY LETTER OF CREDIT MAY BE SENT BY SIMILAR COMMUNICATIONS FACILITY TO THE RESPECTIVE ADDRESSES SET FORTH BELOW. ALL SUCH NOTICES AND COMMUNICATIONS SHALL BE EFFECTIVE UPON RECEIPT BY THE INTENDED RECIPIENT PARTY.

IF TO THE BENEFICIARY OF THIS STANDBY LETTER OF CREDIT:

ISO NEW ENGLAND INC.
ATTENTION: CREDIT DEPARTMENT
1 SULLIVAN RD. HOLYOKE, MA 01040
FAX: 413-540-4569
EMAIL: CREDITDEPARTMENT@ISO-NE.COM

IF TO THE ACCOUNT PARTY:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

IF TO ISSUER:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

_____ _____

[SIGNATURE] [SIGNATURE]

ATTACHMENT 3

ISO NEW ENGLAND MINIMUM CRITERIA FOR MARKET PARTICIPATION OFFICER CERTIFICATION FORM

Certifying Entity:	

I,_____, a duly authorized Senior Officer of _____("Certifying Entity"), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the minimum criteria for market participation requirements set forth in Sections II.A.2 and II.A.3 of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Transmission, Markets and Services Tariff) (the "Policy"), hereby certify that I have full authority to bind Certifying Entity and further certify as follows:

1. Certifying Entity has established or contracted for written policies, procedures, and controls applicable to participation in the New England Markets, approved by Certifying Entity's independent risk management function[1], which provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Certifying Entity is exposed, including, but not limited to, credit risk, liquidity risk, concentration risk, default risk, operation risk, and market risk.

2. Certifying Entity has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets.

3. Certifying Entity has appropriate operating procedures and technical abilities to promptly and effectively respond to all ISO New England communications and directions.

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England's minimum criteria for market participation requirements and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

_____
(Signature)

Print Name:_____

Title: _____

Date: _____

[1] As used in this certification, a Certifying Entity's "independent risk management function" can include appropriate corporate persons or bodies that are independent of the Certifying Entity's trading functions, such as a risk management committee, a risk officer, a Certifying Entity's board or board committee, or a board or committee of the Certifying Entity's parent company.

ATTACHMENT 4

ISO NEW ENGLAND ADDITIONAL ELIGIBILITY REQUIREMENTS

CERTIFICATION FORM

Certifying Entity:	

I,_____, a duly authorized Senior Officer of _____("Certifying Entity"), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the additional eligibility requirements set forth in Section II.A.5 of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Inc. Transmission, Markets and Services Tariff) (the "Policy"), hereby certify that I have full authority to bind Certifying Entity and further certify as follows:

1. Certifying Entity is now and in good faith will seek to remain (check applicable box(es)):

   □ an "appropriate person," as defined in section(s) [ ] of the Commodity Exchange Act (7 U.S.C. § 1 *et seq*.) (specify which section(s) of Commodity Exchange Act sections 4(c)(3)(A) through (J) apply)) (if Certifying Entity is relying on section 4(c)(3)(F), it shall accompany this certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the Certifying Entity's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy);

   □ an "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or

   ☐ a "person who actively participates in the generation, transmission, or distribution of electric energy," as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

2. If at any time Certifying Entity no longer satisfies the criteria in paragraph 1 above, Certifying Entity will immediately notify ISO New England in writing and will immediately cease all participation in the New England Markets.

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England's additional eligibility requirements and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

_____

(Signature)

Print Name:_____

Title: _____

Date: _____

ATTACHMENT 5

ISO NEW ENGLAND CERTIFICATE REGARDING CHANGES TO SUBMITTED RISK MANAGEMENT POLICIES FOR FTR PARTICIPATION

Certifying Entity:	

I,_____, a duly authorized Senior Officer of _____("Certifying Entity"), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the annual certification requirement for FTR market participation regarding its risk management policies, procedures, and controls set forth in Section II.A.2(b) of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Inc. Transmission, Markets and Services Tariff) (the "Policy"), hereby certify that I have full authority to bind Certifying Entity and further certify as follows (check applicable box):

1. □ There have been no changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity's participation in the FTR market.

   OR

2. □ There have been changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity's participation in the FTR market and such changes are clearly identified and attached hereto.*

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England's risk management policy requirements for FTR market participants and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

_____

____

(Signature)

Print Name:_____

Title:

_____

Date:

_____

_____

* As used in this certificate, "clearly identified" changes may include a redline comparing the current written risk management policies, procedures, and controls and the previously submitted written risk management policies, procedures, and controls; or resubmission of the written risk management policies, procedures, and controls with a bulleted list of all changes, including section and/or page numbers.

ATTACHMENT 6

MINIMUM CRITERIA FOR MARKET PARTICIPATION

INFORMATION DISCLOSURE FORM

Date: _____

Prepared by: _____

Customer/Applicant:[1] _____

I, _____, a duly authorized Senior Officer of _____ ("Certifying Entity"), understanding that ISO New England Inc. ("ISO") is relying on this certification provided pursuant to Financial Assurance Policy Section II.A.1(a), hereby certify that I have full authority to bind Certifying Entity and further certify on behalf of Certifying Entity that the information contained herein is true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission:

1. List of all Principals.[2] Please discuss each Principal's relationship with the Certifying Entity and describe each Principal's previous experience related to participation in North American wholesale or retail energy markets or trading exchanges:

[1] Customer and Applicant are each defined in Section II.A of the ISO New England Financial Assurance Policy, Exhibit 1A to Section 1 of the ISO Transmission, Markets, and Services Tariff ("Tariff"). Capitalized terms used but not otherwise defined herein shall have the meaning given to them in the Tariff.

[2] Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission ("FERC"), the Securities and Exchange Commission ("SEC"), the Commodity Futures Trading Commission ("CFTC"), any exchange monitored by the National Futures Association ("NFA"), or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

2. List all material litigation (criminal or civil) against Certifying Entity or any of the Certifying Entity's Principals, Personnel,[1] or Predecessors,[2] arising out of participation in any wholesale or retail energy market (domestic or international) or trading exchanges in the past ten (10) years:
(Enter N/A if not applicable)
3. List all sanctions issued against or imposed upon Certifying Entity, Certifying Entity's Principals, Personnel, or Predecessors, by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges where such sanctions were either imposed in the past ten (10) years or, if imposed prior to that, are still in effect. List all known material ongoing investigations regarding Certifying Entity, Certifying Entity's Principals, Personnel, or Predecessors, imposed by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges:
(Enter N/A if not applicable)

4. Provide a summary of any bankruptcy, dissolution, merger, or acquisition of Certifying Entity in the past ten (10) years (include date, jurisdiction, and other relevant details):
(Enter N/A if not applicable)

5. List all wholesale or retail energy market-related operations in North America where Certifying Entity is currently participating, or, in the past five (5) years, has previously participated other than in the New England Markets (e.g., PJM - FTRs):
(Enter N/A if not applicable)

6. Describe if Certifying Entity or any of Certifying Entity's Principals, Personnel, or any Predecessor of the foregoing ever had its participation or membership in any independent system operator or regional transmission organization (domestic or international) terminated, its registration/membership application denied, or is subject to an existing uncured suspension from participating in the markets of any independent system operator or regional transmission organization (domestic or international), each in the past five (5) years.
(Enter N/A if not applicable)

If you are currently an active participant and this is your annual submission you do not have to complete Question 7 and can skip to the signature block below. If you are in the process of applying for membership with the ISO you are required to answer the additional questions listed below.

7. Describe how Certifying Entity plans to fund its operations, including persons or entities providing financing and such person(s)' or entity(ies)' relationship to the Certifying Entity. Include any relationships that may impact Certifying Entity's ability to (a) comply with the time frames to post

[1] Personnel means any person, current or former, responsible for decision making regarding Certifying Entity's transaction of business in the New England Markets, including, without limitation, decisions regarding risk management and trading, or any person, current or former, with access to enter transactions into ISO systems. Disclosures regarding former Personnel shall only be required for when such Personnel was employed by Certifying Entity.

[4] Predecessor shall mean any person or entity whose liabilities, including liabilities arising under the Tariff, have or may have been retained or assumed by Certifying Entity, either contractually, by operation of law or considering all relevant factors, including the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base.

financial assurance and/or pay invoices or other amounts owed to the ISO, each as required by the Tariff; or (b) provide a first priority perfected security interest in required financial assurance to the ISO:

Certifying Entity: _____

By: _____
(Signature)

Print Name: _____

Title: _____

Date: _____

** To satisfy the disclosure requirements above, a Certifying Entity may attach additional materials and may provide the ISO with filings made to the SEC or other similar regulatory agencies that include substantially similar information to that required above, provided that Certifying Entity clearly indicates where the specific information is located in those filings.

EXHIBIT ID

ISO NEW ENGLAND BILLING POLICY

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EXHIBIT ID ISO NEW ENGLAND BILLING POLICY

SECTION 1 – OVERVIEW

Section 1.1 – Scope. The objective of this ISO New England Billing Policy is to define the billing and payment procedures to be utilized in administering charges and payments due under the Transmission, Markets and Services Tariff and the ISO Participants Agreement, in each case as amended, modified, supplemented and restated from time to time (collectively, the "Governing Documents"). Capitalized terms used but not defined in the ISO New England Billing Policy shall have the meanings specified in Section I. The ISO New England Billing Policy applies to the ISO, the Market Participants, Non-Market Participant Transmission Customers, PTOs, and Market Participants that transact only in the FTR Auction ("FTR-Only Customers") (referred to herein collectively as the "Covered Entities" and individually as a "Covered Entity") for billing and payments procedures for amounts due under the Governing Documents, including without limitation those procedures related to the New England Markets. As reflected and specified in Section 3 hereof, the ISO's obligation to make Payments (as defined below) is contingent on its receipt of sufficient aggregate Charges (as defined below) (or in cases of defaults in Covered Entities' payments of Charges, on the ISO's drawdowns under the ISO New England Financial Assurance Policy or recovery using the mechanisms specified in Section 3, 4 and 5 hereof).

Section 1.2 – Financial Transaction Conventions. The following conventions have been adopted in defining sums of money to be paid or received under the ISO New England Billing Policy:

a) The term "Charge" refers to a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

b) The term "Payment" refers to a sum of money due to a Covered Entity from the ISO. Amounts due to and from the ISO include amounts collected and paid by the ISO as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

c) Where a Covered Entity's total Charges exceed its total Payments for all amounts being billed together in a billing period, the ISO shall issue an "Invoice" for the net Charge owed by such Covered Entity.

d) Where a Covered Entity's total Payments exceed its total Charges for all amounts being billed together in a billing period, the ISO shall issue a "Remittance Advice" for the net Payment owed to the Covered Entity. Invoices and Remittance Advices are collectively referred to herein as "Statements."

Section 1.3 – General Process. Except for special billings, as described in Section 1.4 below, the billing process is performed (i) twice weekly for each complete-day settlement amount for the hourly charges and payments for Real-Time Energy and Day-Ahead Energy and for each complete-day settlement amount for the hourly charges and payments for Real-Time Operating Reserve, Forward Reserves, Regulation service, Emergency Sales, Emergency Purchases, Net Commitment Period Compensation, daily Forward Capacity Market charges and payments ("Daily FCM Charges"), and Inventoried Energy Program charges and payments under Section III, Appendix K of the ISO Transmission, Markets and Services Tariff (all such charges and payments described in this clause (i) being referred to collectively as the "Hourly Charges"); (ii) monthly for all other charges and payments, including without limitation charges relating to the monthly markets, the monthly Forward Capacity Market (exclusive of settlements included in the Hourly Charges) and other ancillary services, Participant Expenses, charges under Section IV of the ISO Transmission, Markets and Services Tariff, monthly meter adjustments, Qualification Process Cost Reimbursement Deposits (including the annual true-up of those Qualification Process Cost Reimbursement Deposits), state sales tax and related charges, any pass-through charges where the ISO acts as agent (including communications related charges, Open Access Same-Time Information System related charges, and fees related to the Shortfall Funding Arrangement), and charges under the OATT (*other than* charges arising under Schedules 1, 8, and 9 to the OATT, which charges are addressed in clause (iii) below) (all such charges and payments described in this clause (ii) being referred to collectively as ("Non-Hourly Charges" and, together with Hourly Charges, as "ISO Charges"), except in the case of Covered Entities who have requested and received a weekly payment arrangement for Non-Hourly Charges under the ISO New England Financial Assurance Policy that is Exhibit IA to Section I of the ISO Transmission, Markets and Services Tariff (the "ISO New England Financial Assurance Policy"); and (iii) monthly for all charges and payments under Schedules 1, 8 and 9 to the OATT (all such

charges and payments described in this clause (iii) being referred to collectively as "Transmission Charges"). There are two major steps in the billing process:

a) *Statement Issuance*. The ISO will issue an Invoice or Remittance Advice showing the net amounts due from or owed to a Covered Entity. This Statement is determined from the preliminary statements of the New England Markets, applicable the ISO Charges and/or Transmission Charges due under the Governing Documents (including amounts due under the ISO New England Financial Assurance Policy), as well as applicable adjustments. Prior to January 1 of any calendar year, the ISO will post or make available a list of the dates in the new calendar year on which Statements will be issued, due and paid. Billing and payment holidays will be the same as the ISO's settlement holidays, as listed on the ISO's website from time to time.

b) *Electronic Funds Transfer ("EFT").* EFTs related to Invoices and Remittance Advices are performed in a two-step process, as described below, in which all Invoices are paid first and all Remittance Advices are paid later.

Section 1.4 – Special Billings. In addition to the regular billing process described above, the ISO will issue special, extraordinary Statements as and when required under the Governing Documents or in order to adjust for special circumstances. Such Statements shall be payable in accordance with the instructions set forth therein.

Section 1.5 – Conflicts with Governing Documents. Except as set forth herein, to the extent any provision hereof conflicts with any provision of any Governing Document, the provision in the Governing Document shall govern.

SECTION 2 - TIMING AND CONTENT OF STATEMENTS.

Section 2.1 – Statements for Hourly Charges. On each Monday and each Wednesday or on the following Business Day if such Monday or Wednesday is not a Business Day, the ISO shall provide electronically to each Covered Entity a Statement showing all complete-day settlement amounts for each of the Hourly Charges incurred and not reflected on a previously issued Statement. Each such Statement will cover only days with complete settled data. Accordingly,

some Statements may have fewer days of settled data for certain Hourly Charges if fewer days have been settled for those Hourly Charges on the morning of the day that such Statements are issued; a following Statement may have more days of settled data for those Hourly Charges when it becomes possible to catch up on the settled data. Statements will include contiguous month-to-month hourly market billing data and will have separate line items for any hourly market data that may cross calendar months. For example, if a Statement's billing period includes May 30 through June 2, and all of those days are fully settled, the June 8 Statement would have one line item for the period May 30 to May 31 and one line item for the period June 1 to June 2. The Job Aid on the ISO web site will be updated weekly for any information necessary to be distributed through that medium.

Section 2.2 – Monthly Statements for Non-Hourly Charges. The first Statement issued on a Monday after the ninth of a calendar month will include both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month (hereinafter sometimes referred to as a "Monthly Statement"). Resettlements determined in accordance with the procedures set forth in Market Rule 1 will be included in the monthly Statement for Non-Hourly Charges.

Section 2.3 – Statements for Weekly Billing Non-Hourly Charges. The ISO shall implement any weekly billing arrangements for Non-Hourly Charges effected under the ISO New England Financial Assurance Policy in accordance therewith and with the procedures set forth in Section 7 below.

Section 2.4 – Contents of Statements. Each Statement for Hourly and Non-Hourly Charges will include all of the following line items that are applicable to the Covered Entity receiving such Statement for the period to which such Statement relates:

a) *Invoice or Remittance Advice Amount*. The net amount of all Charges and Payments owed by or due to a Covered Entity for the relevant Statement. The ISO shall issue an Invoice where the Covered Entity owes monies. The ISO shall issue a Remittance Advice where the Covered Entity is owed monies.

b) *OATT Charges and Payments.* The Charges owed by and the Payments owed to the Covered Entity under the OATT *other than* Transmission Charges, which are billed separately under Section 2.5 below.

c) *ISO Self-Funding Charges.* The Charges owed by the Covered Entity under Section IV of the Transmission, Markets and Services Tariff, categorized by the section or schedule under which such Charges arise.

d) *Markets Charges and Payments.* The Hourly Charges owed by and the Payments for Hourly Charges owed to the Covered Entity as a result of transactions in each of the New England Markets administered by the ISO under Section III of the Transmission, Markets and Services Tariff.

e) *Monthly Forward Capacity Market Charges and Payments.* The Non-Hourly Charges owed by and the Payments for Non-Hourly Charges owed to the Covered Entity as a result of Capacity Performance Payments, System-Backed Export Charges, and other transactions in the Forward Capacity Market.

f) *Participant Expenses*. As defined in the Participants Agreement, the Covered Entity's share of costs and expenses that are incurred pursuant to authorization of the Participants Committee and are not considered costs and expenses of ISO.

g) [Reserved for Future Use]

h) *Other Amounts due under the Participants Agreement.* The Charges owed by or the Payments owed to the Covered Entity under the Participants Agreement to the extent that those amounts are not included in items (b)-(g) above.

i) *Other Non-Hourly Charges, Payments or Adjustments*. Any other Non-Hourly Charges, Payments for Non-Hourly Charges, or adjustments owed by or to the Covered Entity that are not included in items (b)-(h) above. These items may be due to retroactive billing adjustments, late payment fees, penalties or other items collectible under the Governing Documents.

j) *Billing Periods*. The billing period (from and to dates) covered for each line item on the Statement. The billing periods for the various line items are not necessarily the same because of differences in timing of settlements and because of retroactive adjustments.

k) *Payment Due Date and Time.* If the Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO.

l) *Wire Transfer Instructions*. Details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which ISO Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for ISO Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.5 – Monthly Statements for Transmission Charges. On the same date when each Monthly Statement is issued, the ISO shall provide electronically to each Covered Entity owing or owed any Transmission Charges for the preceding month a Statement (which may be combined with that Monthly Statement) showing all of the Transmission Charges for that Covered Entity for that preceding month (hereinafter sometimes referred to as a "Transmission Statement"). Any resettlements of Transmission Charges will also be included on the Transmission Statement. Each Transmission Statement will also include: (i) the billing month covered by the Transmission Statement; (ii) if the Transmission Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO; and (iii) details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which Transmission Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for Transmission Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.6 – Certain Subsequent Adjustments to Previously Issued Statements.

a) *Adjustments Requested by Covered Entities*. Covered Entities supplying Regional Network Load and other input data to the ISO for use by the ISO in developing Statements shall use reasonable care to assure that the data supplied is complete and accurate. Should a Covered Entity supplying input data subsequently determine that the data supplied was incorrect, that Covered Entity shall notify the ISO promptly of the error and submit corrected data as soon as practicable. All errors in input data for a calendar month shall be corrected in one submission. If the error is detected and corrected data is provided within the time frames set forth below, the ISO will issue corrected Statements to reflect the newly supplied data.

Type of Adjustment	**Corrected Data Must be Submitted By**
Adjustments to Monthly Regional Network Load Submissions	20th day of the fourth (4th) month after the Regional Network Load Month
Adjustments to Annual Revenue Requirements Submissions	Annually during the rate development process, which is administered by the PTO Working Group
Adjustments to Annual Transmission, Markets and Services Tariff Section II, Schedule I Submissions	Annually during the rate development process, which is administered by the PTO Working Group

If the data correction is not submitted within the applicable time frame set forth above, the obligation of the ISO to issue corrected Statements reflecting that adjustment shall be as set forth in a written re-billing protocol, developed in consultation with the NEPOOL Budget and Finance Subcommittee, and as may be amended from time to time in consultation with the NEPOOL Budget and Finance Subcommittee, and posted on the ISO website. The re-billing protocol shall provide, for each category of adjustment listed above, whether and to what extent the adjustment shall be prospective or retroactive and the timing of the adjustment. If the corrected data is not submitted within the applicable time frame, the ISO may assess each Covered Entity submitting corrected data on an untimely basis its costs in generating and issuing the corrected Statement. The written re-billing protocol shall include a fee schedule for this purpose.

b) *Adjustments Triggered by ISO Audit*. The ISO will review the results of internal and outsourced audits with the PTO Administrative Committee and the Participants Committee or its delegee. The reasonable costs to the ISO of the re-billing shall be allocated to Schedule 1 of Section IV of the Transmission, Markets and Services Tariff.

c) *Adjustments Reflecting Compliance with an Order of the Commission or other Regulatory or Judicial Authority With Jurisdiction*. Adjustments required to effect compliance with an order of the Commission (or any other regulatory or judicial authority with jurisdiction to interpret and/or enforce the provisions of the Governing Documents) shall be completed by the ISO in compliance with such order. The costs of any such re-billing to the ISO shall be allocated among the Covered Entities in accordance with the provisions of the Transmission, Markets and Services Tariff.

d) Nothing in this Section 2.6 shall affect resettlements of the New England Markets under Market Rule 1.

SECTION 3 – PAYMENT PROCEDURES.

All Payments (including prepayments as described in Section 3.1(e) below) made by the ISO will in all instances be made by EFT or in immediately available funds payable to the account designated to the ISO by the Covered Entity to which such Payment is due. Payments made by Covered Entities shall be made by EFT to the account designated by the ISO.

Section 3.1 – Invoice Payments.

a) *Payment Date*. Except in the case of special billings, all Charges due shall be paid to and received by the ISO not later than the second (2nd) Business Day after the Invoice on which they appeared was issued (the "Invoice Date") so long as the ISO issues such Invoice to the Covered Entities by 11:00 a.m. Eastern Time on the Invoice Date. If the ISO issues an Invoice after 11:00 a.m. Eastern Time on the Invoice Date, the charges on such Invoice will be paid not later than the third (3rd) Business Day after such Invoice Date. Notwithstanding the

foregoing, a Non-Market Participant Transmission Customer will in no event be required to make a payment on an Invoice any sooner than provided in Section II of the Transmission, Markets and Services Tariff.

b) *Right to Alter Payment Date*. The ISO may establish the dates on which payments are due in the case of a special billing; provided, however, that, (i) payment on any special billing invoice shall not be due prior to the second (2nd) Business Day after the Invoice is issued, and (ii) a Non-Market Participant Transmission Customer shall not be required to make a payment on an Invoice any sooner than provided in Section II of the Transmission, Markets and Services Tariff.

c) *Payments Received by the ISO*. Each Covered Entity owing monies to the ISO, either in the ISO's individual capacity, or as agent for NEPOOL, shall remit the amount shown on its Invoice no later than the date such payment is due. Disputed Amounts shall be paid in accordance with clause (d) below. All Invoices shall be paid by EFT, except that (i) Covered Entities (other than Unqualified New Market Participants and Returning Market Participants under the ISO New England Financial Assurance Policy that are not Provisional Members) may, and any Provisional Member must, pay any Invoice for ISO Charges (but not for Transmission Charges) by instructing the ISO (either on a case-by-case basis or pursuant to a standing instruction) in writing to draw on collateral maintained in a shareholder account created pursuant to the ISO New England Financial Assurance Policy provided by such Covered Entity under the ISO New England Financial Assurance Policy for such Invoice, provided that the failure of a Provisional Member to provide such an instruction to the ISO shall not, in and of itself, be deemed to be a default under the ISO New England Billing Policy and (ii) any Covered Entity may instruct the ISO to auto-debit an account identified by that Covered Entity to pay all Invoices issued by the ISO and in such case the Covered Entity will direct the bank or other institution holding that account to permit the ISO to auto-debit that account to pay all such Invoices on the date they are due. Any instruction to pay any Invoice by drawing on collateral maintained in a shareholder account or to auto-debit an account must be received by at least 5:00 p.m. (Eastern Time) on the day that is two

Business Days prior to the Invoice Date. The amount of a Covered Entity's collateral maintained in a shareholder account will immediately be reduced by the amount drawn to pay an Invoice for ISO Charges pursuant to a standing instruction. Nothing set forth in this section will reduce the financial assurance obligation otherwise applicable to any Covered Entity that instructs the ISO to draw on collateral maintained in a shareholder account or to auto-debit an account to pay an Invoice, and the ISO is not liable for any default resulting from a draw on collateral maintained in a shareholder account to pay an Invoice or for any overdraft charges resulting from any auto-debit.

d) *Payments Pending Resolution of a Dispute.* Any Covered Entity that disputes the amount due, including an amount due for Participant Expenses, on any Invoice for service other than transmission service under Section II of the Transmission, Markets and Services Tariff shall pay to the ISO all amounts due on such Invoice, including any such Disputed Amounts. Such payment shall in no way prejudice the right of such Covered Entity to seek reimbursement of such Disputed Amounts, including accrued interest on such amounts at the Commission's standard rate, set forth in 18 C.F.R. Section 35.19, pursuant to the Billing Dispute Resolution Procedures provided in Section 6 below.

Any Covered Entity that disputes the amount due on any Invoice for transmission service under the Transmission, Markets and Services Tariff shall pay to the ISO all amounts not in dispute in accordance with the ISO New England Billing Policy and shall pay (or, in the case of an auto-debit payment or a payment for ISO Charges pursuant to a standing instruction, as described above, direct the ISO to pay) such Disputed Amounts into an independent escrow account designated by the ISO, which account shall be established at a banking institution acceptable to the ISO and the Covered Entity challenging the amount due and shall accrue interest at a prevailing market rate. Such amount in dispute shall be held in escrow pending the resolution of such dispute in accordance with the applicable Governing Document(s). The shortfall of funds available to pay Remittance Advices resulting from the amount in dispute being held in an escrow account shall be allocated among the Covered Entities according to the two-step allocation process described in Section 3.3 (for ISO Charges) and in Section 3.4

(for Transmission Charges) for the applicable type of Covered Entity disputing the Charges, subject to payment to all Covered Entities being allocated a portion of the shortfall, with applicable interest (if any), once the dispute is resolved with the funds in such escrow account or with other amounts provided by the Covered Entity losing such dispute.

e) *Prepayments*. A Covered Entity may prepay any Invoice, in whole or in part, according to the following procedures:

(i) only two such prepayments shall be made by any Covered Entity in any calendar week; only five such prepayments shall be made in any rolling 365-day period; and no prepayments shall be made on a Friday;

(ii) each prepayment will be applied only to the next subsequent Invoice issued;

(iii) prepayments and payments for issued Invoices must be made in separate wire transfers;

(iv) for purposes of calculating a Covered Entity's financial assurance obligations under the ISO New England Financial Assurance Policy, prepayments will be applied first to Hourly Charges, then any remaining prepayment will offset the Covered Entity's financial assurance obligations on a dollar-for-dollar basis;

(v) if ISO Charges and Transmission Charges are billed on separate Invoices, then separate prepayments must be made for those ISO Charges and Transmission Charges (the ISO will account for each prepayment separately and will only apply each prepayment to the designated Charges);

(vi) if a prepayment exceeds the amount due on the next subsequent Invoice issued, then the prepayment will be applied to that Invoice first, and then to the extent any amount is left after paying that Invoice, the Covered Entity making that prepayment may direct at the time of the prepayment that the excess be deposited with its collateral maintained in a shareholder account created pursuant to the ISO New England Financial Assurance Policy, and if the Covered Entity does not direct the ISO to make that deposit, the excess will be returned to the Covered Entity. Under either circumstance, the deposit to the shareholder account or the return of excess funds will occur on the next date when the ISO pays Remittances; and

(vii) all prepayments will be held in the ISO's settlement account until the Invoice payments are due, and no interest will be paid to any Covered Entity on any prepayments provided by it.

Section 3.2 – ISO Payment of Remittance Advice Amounts. The Payment Date for a Remittance Advice shall be the fourth (4th) Business Day following the date on which the Remittance Advice was issued (the "Remittance Advice Date") so long as the ISO issues such Remittance Advice by 11:00 a.m. Eastern Time on the Remittance Advice Date. If the ISO issues a Remittance Advice after 11:00 a.m. Eastern Time on the Remittance Advice Date, the Payment Date for that Remittance Advice shall be the fifth (5th) Business Day after the Remittance Advice Date.

Section 3.3 -Payment Default for ISO Charges. If the ISO, in its reasonable opinion, believes that all or any part of any amount of ISO Charges due to be paid to the ISO by any Covered Entity will not or has not been paid when due (other than in the case of (i) a payment dispute for any amount due for transmission service under the OATT or (ii) any amounts due for NEPOOL GIS API Fees) (the "Default Amount"), then the following procedures shall apply:

a) *Priority of Payments*. The ISO shall use moneys received by it from Covered Entities for an Invoice for ISO Charges to pay all amounts due to the ISO under Section IV of the Transmission, Markets and Services Tariff, all amounts due to NEPOOL for Participant Expenses, and all amounts due to the ISO for acting as Project Manager for the generation information system (the "NEPOOL GIS") before making any payments to any Covered Entities. After paying all amounts due to the ISO and NEPOOL but prior to making any payments to any Covered Entities, the ISO shall use moneys received by it from Covered Entities for ISO Charges to pay all amounts due from NEPOOL to the entity or entities that develop, administer, operate and maintain the NEPOOL GIS (the "NEPOOL GIS Administrator") for those services (other than NEPOOL GIS API Fees). After paying all amounts due to the ISO and NEPOOL for Participant Expenses and all amounts due to the NEPOOL GIS Administrator for the development, administration, operation and maintenance of the NEPOOL GIS but prior to making any payments to any Covered Entities, the ISO shall use moneys received by it from Covered Entities for ISO Charges to pay any and all amounts due with respect to the Shortfall Funding Arrangement. NEPOOL GIS API Fees

shall only be paid to the NEPOOL GIS Administrator to the extent that each Covered Entity or NEPOOL Participant owing such NEPOOL GIS API Fees has paid the full amount of all ISO Charges due on the Statement on which such NEPOOL GIS API Fees appear.

b) *Use of Set-Offs.* The ISO shall use any and all rights of set-off it has under the Governing Documents, including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy against a defaulting Covered Entity with respect to ISO Charges due to that Covered Entity to the extent necessary to pay the Default Amount, together with any interest accrued thereon and any late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, due from such Covered Entity.

c) *Enforcing the Security of a Defaulting Party*. If and to the extent that the procedure described in clause (b) above is insufficient to effect payment of the Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall use the financial assurance(s) provided by the defaulting Covered Entity under the ISO New England Financial Assurance Policy to the extent necessary to pay the Default Amount and such interest and late charges. Any use of financial assurance(s) shall be undertaken in compliance with the ISO New England Financial Assurance Policy.

d) *Action Against a Defaulting Party or Recovery from an FCM Affiliate Guaranty.* If and to the extent that the procedures described in clauses (b) and (c) above are insufficient to effect payment of the Default Amount and the Covered Entity has an FCM Affiliate Guaranty (as described in Section VII of the ISO New England Financial Assurance Policy) in place, the ISO shall use the monies received from the guarantor under such guaranty to cover the portion of the Default Amount related to a Capacity Performance Payment. If and to the extent that the procedures described in clauses (b) and (c) above are insufficient to effect payment of the Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall take appropriate actions to recover the

Default Amount and such accrued interest and late charges, which actions may include, without limitation, initiating proceedings in accordance with the appropriate dispute resolution mechanisms or actions with Covered Entities or before the Commission or a court of competent jurisdiction against the defaulting Covered Entity. Before initiating any such proceedings, the ISO shall consult with the Chair of the NEPOOL Budget and Finance Subcommittee or NEPOOL counsel. Any amounts incurred by the ISO or any Market Participant in connection with any such action or proceeding shall be paid by the defaulting Covered Entity.

e) *Late Payment Account.* If and to the extent that the procedures described in clauses (b), (c) and (d) above are insufficient to effect payment of the Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) by the time the corresponding Payment to the Covered Entities is due, the ISO shall withdraw from the Late Payment Account, as that term is defined in Section 4 of the ISO New England Billing Policy, an amount equal to such unpaid Default Amount, to the extent that such amount is available in the Late Payment Account, and shall apply such amount to any shortfall in Payments resulting from the Default Amount not being paid. To the extent that the amount on deposit in the Late Payment Account on any date is insufficient to pay all Unsecured Default Amounts and Uncovered Default Amounts (each as defined below) on that date, the amount in the Late Payment Account shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts on or total Unsecured Default Amounts outstanding. Amounts withdrawn from the Late Payment Account and applied toward any shortfall resulting from the Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Default Amount. If and to the extent that such Default Amount, interest thereon and/or late charges with respect thereto are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the defaulting Covered Entity), such

amounts shall first be used to pay Covered Entities for the amount of such Default Amount allocated to them under clauses (h), (i) and (j) below, with interest thereon, and then, after all such amounts have been paid to Covered Entities, such Default Amount, interest and/or late charges shall be deposited into the Late Payment Account in accordance with Section 4 of the ISO New England Billing Policy.

f) *Payment Default Shortfall Fund.* To the extent that the procedures described in clauses (b), (c), (d) and (e) above are insufficient to effect payment of the Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) the ISO will draw on the Shortfall Funding Arrangement to the extent the Shortfall Funding Arrangement is available at the time, and to the extent the Shortfall Funding Arrangement is not available at the time, the ISO will withdraw from the Payment Default Shortfall Fund, an amount equal to such unpaid Default Amount and shall apply such amount to the shortfall in Payments resulting from the Default Amount not being paid. To the extent that the amount on deposit in the Payment Default Shortfall Fund on any date is insufficient to pay all Unsecured Default Amounts, Uncovered Default Amounts, Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined below) on that date (after applying all amounts in the Late Payment Account for defaults on ISO Charges and all amounts in the Transmission Late Payment Account for defaults on Transmission Charges on that date), the amount in the Payment Default Shortfall Fund on that date shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts and all Unsecured Default Amounts, then such amount shall be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, Unsecured Default Amounts and Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts, total Unsecured Default Amounts, total Uncovered Transmission Default

Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts drawn on the Shortfall Funding Arrangement and/or withdrawn from the Payment Default Shortfall Fund and applied to any shortfall resulting from the Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Default Amount. If and to the extent that a Default Amount which is paid through a draw on the Shortfall Funding Arrangement and/or through a withdrawal from the Payment Default Shortfall Fund, interest on such a Default Amount and/or late charges with respect to such a Default Amount are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the Covered Entity), such amounts shall be paid to certain of the Covered Entities as set forth in Section 5.4 below.

g) *Congestion Revenue Fund*. If during any billing period congestion payments exceed congestion charges under Manual 28 (hereinafter a "Congestion Shortfall"), such that there is a shortfall in the total settlement for that week due to congestion, the ISO will draw from the Congestion Revenue Fund established and funded under Manual 28 to make up for the shortfall. To the extent there are insufficient funds in the Congestion Revenue Fund to cover that Congestion Shortfall, the ISO will recover the uncovered Congestion Shortfall pursuant to the allocation process set forth in Manual 28, Section 6. The ISO will true-up amounts drawn for Congestion Shortfalls on a monthly basis and reflect that true-up in the Statements reflecting Non-Hourly Charges.

h) Reduction of Payments and Increases in Charges for Unsecured Municipal Market Participants

(i) If and to the extent that (A) the defaulting Covered Entity is a Municipal Market Participant (as defined in the ISO New England Financial Assurance Policy) with a Market Credit Limit or a Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy (an "Unsecured Municipal Market Participant") and (B) the procedures described in clauses (b), (c), (d), (e), (f) and (g) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to

NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Municipal Market Participants owed monies for ISO Charges for the billing period to which the payment default relates (the "Default Period"), pro rata based on the ISO Charges owed to those Unsecured Municipal Market Participants, to the extent necessary to clear its accounts for ISO Charges due to Unsecured Municipal Market Participants by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.3(h)(i) shall not exceed the defaulting Unsecured Municipal Market Participant's Market Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Municipal Default Amount"). As funds attributable to an Unsecured Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Default Amount, shall be distributed pro rata to the Unsecured Municipal Market Participants that did not receive the full amount of their Payments as a result of such Unsecured Municipal Default Amount not being paid, up to the full amount that such Unsecured Municipal Market Participants did not receive as a result of such Unsecured Municipal Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Municipal Default Amount remains unpaid to Unsecured Municipal Market Participants on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Unsecured Municipal Default Amount remaining unpaid shall be reallocated among all of the Unsecured Municipal Market Participants receiving Statements for ISO charges for the Default Period (other than the Unsecured Municipal Market Participant defaulting on its payment obligations), pro rata based, for each Unsecured Municipal Market Participant being allocated

a share of the Unsecured Municipal Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Unsecured Municipal Market Participant that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Unsecured Municipal Market Participant that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Municipal Market Participant with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and an Unsecured Municipal Market Participant with $1,000 of Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Unsecured Municipal Default Amount under this clause (h)(ii). Each Unsecured Municipal Market Participant that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Unsecured Municipal Default Amount remaining unpaid under this clause (h)(ii). As funds attributable to an Unsecured Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Default Amount, shall be distributed to the Unsecured Municipal Market Participants pro rata based on their allocation of the Unsecured Municipal Default Amount under this clause (h)(ii), up to the full amount of such Unsecured Municipal Default Amount allocated to each such Unsecured Municipal Market Participant, with interest thereon.

(iii) An Unsecured Municipal Market Participant will not be allocated any Unsecured Municipal Default Amounts under this Section 3.3(h) for any Default Period if, at the start of the calendar year in which the applicable Default Period occurred, that Unsecured Municipal Market Participant provided the ISO with a written request to opt out of that allocation of Unsecured Municipal Default Amounts and that Unsecured Municipal Market Participant provides the ISO with additional financial assurance in the full amount of all of its "Financial Assurance

Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

i) *Reduction of Payments and Increases in Charges for Unsecured Non-Municipal Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity (x) is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and (y) has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy (each such Covered Entity being referred to herein as an "Unsecured Non-Municipal Covered Entity") and (B) the procedures described in clauses (b), (c), (d), (e), (f), and (g) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Non-Municipal Covered Entities owed monies for ISO Charges for the applicable Default Period, pro rata based on the ISO Charges owed to those Unsecured Non-Municipal Covered Entities, to the extent necessary to clear its accounts for ISO Charges due to Unsecured Non-Municipal Covered Entities by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.3(i)(i) shall not exceed the defaulting Unsecured Non-Municipal Covered Entity's Market Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Non-Municipal Default Amount"). As funds attributable to an Unsecured Non-Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Default Amount, shall be distributed pro rata to the Unsecured Non-Municipal Covered

Entities that did not receive the full amount of their Payments as a result of such Unsecured Non-Municipal Default Amount not being paid, up to the full amount that such Unsecured Non-Municipal Covered Entities did not receive as a result of such Unsecured Non-Municipal Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Non-Municipal Default Amount remains unpaid to Unsecured Non-Municipal Covered Entities on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Unsecured Non-Municipal Default Amount remaining unpaid shall be reallocated among all of the Unsecured Non-Municipal Covered Entities receiving Statements for ISO Charges for the Default Period (other than the Unsecured Non-Municipal Covered Entity defaulting on its payment obligations), pro rata based, for each Unsecured Non-Municipal Covered Entity being allocated a share of the Unsecured Non-Municipal Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Unsecured Non-Municipal Covered Entity that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Unsecured Non-Municipal Covered Entity that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Non-Municipal Covered Entity with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and an Unsecured Non-Municipal Covered Entity with $1,000 of Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Unsecured Non-Municipal Default Amount under this clause (i)(ii). Each Unsecured Non-Municipal Covered Entity that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Unsecured Non-Municipal Default Amount remaining unpaid under this clause (i)(ii). As funds attributable to an Unsecured Non-Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after

such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Default Amount, shall be distributed to the Unsecured Non-Municipal Covered Entities pro rata based on their allocation of the Unsecured Non-Municipal Default Amount under this clause (i)(ii), up to the full amount of such Unsecured Non-Municipal Default Amount allocated to each such Unsecured Non-Municipal Covered Entity, with interest thereon.

(iii) An Unsecured Non-Municipal Covered Entity will not be allocated any Unsecured Non-Municipal Default Amounts under this Section 3.3(i) for any Default Period if, at the start of the calendar year in which the applicable Default Period occurred, that Unsecured Non-Municipal Covered Entity provided the ISO with a written request to opt out of that allocation of Unsecured Non-Municipal Default Amounts and that Unsecured Non-Municipal Covered Entity provides the ISO with additional financial assurance in the full amount of all of its "Financial Assurance Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

j) *Reduction of Payments and Increase in Charges for Other Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity is not an Unsecured Municipal Market Participant or an Unsecured Non-Municipal Covered Entity (referred to together herein as an "Unsecured Covered Entity") or the Default Amount exceeds the Unsecured Municipal Default Amount or the Unsecured Non-Municipal Default Amount (referred to together herein as the "Unsecured Default Amount") for that Covered Entity and (B) the procedures described in clauses (b), (c), (d), (e), (f), (g), and (h) or (i) (if applicable) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to those Covered Entities owed monies for ISO Charges for that Default Period, pro rata based on the amounts owed to all Covered Entities, to the extent necessary to clear its accounts for ISO Charges by the close of banking

business on the date such Payments are due (after giving effect to clause (h) or (i) above if applicable) (the amount of such reduction in Payments for ISO Charges after giving effect to clause (h) or (i) above (if applicable) is referred to herein as the "Uncovered Default Amount"). For the avoidance of doubt, the Uncovered Default Amount is equal to the Default Amount minus any Unsecured Default Amount. As funds attributable to an Uncovered Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Default Amount, shall be distributed pro rata to the Covered Entities that did not receive the full amount of their Payments as a result of such Uncovered Default Amount not being paid, up to the full amount that such Covered Entities did not receive as a result of such Uncovered Default Amount not being paid, with interest thereon.

(ii) To the extent that any amount of an Uncovered Default Amount remains unpaid to Covered Entities on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Uncovered Default Amount remaining unpaid shall be reallocated among all of the Covered Entities receiving Statements for ISO Charges for the Default Period (other than the Covered Entity defaulting on its payment obligations), pro rata based, for each Covered Entity being allocated a share of the Uncovered Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Covered Entity that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Covered Entity that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, a Covered Entity with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and a Covered Entity with $1,000 of ISO Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Uncovered Default Amount under this clause (j)(ii). Each Covered Entity that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately

following the Default Period adjusted as necessary to reflect its obligation for the Uncovered Default Amount remaining unpaid under this clause (j)(ii). As funds attributable to an Uncovered Default Amount are received by the ISO (including amounts received through financial assurance provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Uncovered Default Amount, shall be distributed to the Covered Entities pro rata based on their allocation of the Uncovered Default Amount under this clause (j) (ii), up to the full amount of such Uncovered Default Amount allocated to each such Covered Entity, with interest thereon.

k) *Order of Settlement*. As amounts on Default Amounts are received by the ISO, the oldest outstanding ISO Charges will be settled first in the order of the creation of such debts.

l) Notwithstanding the other provisions of this Section 3.3, an unpaid amount shall not be considered a "Default Amount," and the ISO will not take any of the actions described in the suspension provisions of the ISO New England Financial Assurance Policy or in this Section 3.3 with respect to that unpaid amount, if the total unpaid amount is attributable to Qualification Process Cost Reimbursement Deposits (including any annual true-up of those amounts) and/or NEPOOL GIS API Fees. To the extent that a Covered Entity or a NEPOOL Participant pays only a part of an Invoice that includes a Charge for a Qualification Process Cost Reimbursement Deposit and/or a Charge for NEPOOL GIS API Fees, the unpaid amount shall first be allocated to the unpaid NEPOOL GIS API Fees, and then to that Qualification Process Cost Reimbursement Deposit, and other Charges on that Invoice will only be considered not to have been paid if the unpaid amount exceeds the amount of the Qualification Process Cost Reimbursement Deposit and any unpaid NEPOOL GIS API Fees. The sole consequence of a Covered Entity's or a NEPOOL Participant's failure to pay NEPOOL GIS API Fees, after application of any set-off rights against the Covered Entity or NEPOOL Participant and any financial assurance provided by that Covered Entity or NEPOOL Participant, shall be denial to that Covered Entity or NEPOOL

Participant of access to any application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

Section 3.4 – Payment Default for Transmission Charges. If the ISO, in its reasonable opinion, believes that all or any part of any amount of Transmission Charges due to be paid to the ISO by any Covered Entity will not or has not been paid when due (the "Transmission Default Amount"), then the following procedures shall apply:

a) *Use of Set-Offs*. The ISO shall use any and all rights of set-off it has under the Governing Documents, including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, against a defaulting Covered Entity with respect to Transmission Charges due to that Covered Entity to the extent necessary to pay the Default Amount, together with any interest accrued thereon and any late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, due from such Covered Entity.

b) *Enforcing the Security of a Defaulting Party*. If and to the extent that the procedure described in clause (a) above is insufficient to effect payment of the Transmission Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall use the financial assurance(s) provided by the defaulting Covered Entity under the ISO New England Financial Assurance Policy to the extent necessary to pay the Transmission Default Amount and such interest and late charges. Any use of financial assurance(s) shall be undertaken in compliance with the ISO New England Financial Assurance Policy.

c) *Action Against a Defaulting Party*. If and to the extent that the procedures described in clauses (a) and (b) above are insufficient to effect payment of the Transmission Default Amount and all interest accrued theron and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall take appropriate actions to recover the Transmission Default Amount and such accrued interest and late charges, which

actions may include, without limitation, initiating proceedings in accordance with the appropriate dispute resolution mechanisms or actions with Covered Entities or before the Commission or a court of competent jurisdiction against the defaulting Covered Entity. Before initiating any such proceedings, the ISO shall consult with the Chair of the NEPOOL Budget and Finance Subcommittee or NEPOOL counsel. Any amounts incurred by the ISO or any Market Participant in connection with any such action or proceeding shall be paid by the defaulting Covered Entity.

d) *Transmission Late Payment Account*. If and to the extent that the procedures described in clauses (a), (b) and (c) above are insufficient to effect payment of the Transmission Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) by the time the corresponding Payment to the Covered Entities is due, the ISO shall withdraw from the Transmission Late Payment Account, as that term is defined in Section 4 of the ISO New England Billing Policy, an amount equal to such unpaid Transmission Default Amount, to the extent that such amount is available in the Transmission Late Payment Account, and shall apply such amount to any shortfall in Payments resulting from the Transmission Default Amount not being paid. To the extent that the amount on deposit in the Transmission Late Payment Account on any date is insufficient to pay all Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined below) on that date, the amount in the Transmission Late Payment Account shall first be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts withdrawn from the Transmission Late Payment Account and applied toward any shortfall resulting from the Transmission Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Transmission Default Amount. If and to the extent that such Transmission Default Amount, interest thereon and/or late charges with respect thereto are subsequently collected (including as a result

of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the defaulting Covered Entity), such amounts shall first be used to pay Covered Entities for the amount of such Transmission Default Amount allocated to them under clause (f), (g) and (h) below, with interest thereon, and then, after all such amounts have been paid to Covered Entities, such Transmission Default Amount, interest and/or late charges shall be deposited into the Transmission Late Payment Account in accordance with Section 4 of the ISO New England Billing Policy.

e) *Payment Default Shortfall Fund* To the extent that the procedures described in clauses (a), (b), (c) and (d) above are insufficient to effect payment of the Transmission Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy), the ISO will draw on the Shortfall Funding Arrangement to the extent the Shortfall Funding Arrangement is available at the time, and to the extent the Shortfall Funding Arrangement is not available at the time, the ISO will withdraw from the Payment Default Shortfall Fund, an amount equal to such unpaid Transmission Default Amount and shall apply such amount to the shortfall in Payments resulting from the Transmission Default Amount not being paid. To the extent that the amount on deposit in the Payment Default Shortfall Fund on any date is insufficient to pay all Unsecured Default Amounts, Uncovered Default Amounts, Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined herein) on that date (after applying all amounts in the Late Payment Account for defaults on ISO Charges and all amounts in the Transmission Late Payment Account for defaults on Transmission Charges on that date), the amount in the Payment Default Shortfall Fund on that date shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts and all Unsecured Default Amounts, then such amount shall be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, Unsecured Default Amounts and Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured

Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts, total Unsecured Default Amounts, total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts drawn on the Shortfall Funding Arrangement and/or withdrawn from the Payment Default Shortfall Fund and applied to any shortfall resulting from the Transmission Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Transmission Default Amount. If and to the extent that a Transmission Default Amount which is paid through a draw on the Shortfall Funding Arrangement and/or through a withdrawal from the Payment Default Shortfall Fund, interest on such a Transmission Default Amount and/or late charges with respect to such a Transmission Default Amount are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the Covered Entity), such amounts shall be paid to certain of the Covered Entities as set forth in Section 5.4 below.

f) *Reduction of Payments and Increases in Transmission Charges for Unsecured Municipal Market Participants.*

(i) If and to the extent that (A) the defaulting Covered Entity is an Unsecured Municipal Market Participant and (B) the procedures described in clauses (a), (b), (c), (d), and (e) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Municipal Market Participants owed monies for Transmission Charges for that billing period (the "Transmission Default Period"), pro rata based on the Transmission Charges owed to those Unsecured Municipal Market Participants, to the extent necessary to clear its accounts for Transmission Charges due to Unsecured Municipal Market Participants by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.4(f) shall not exceed the defaulting Unsecured Municipal Market Participant's Transmission Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Municipal Transmission Default Amount"). As funds

attributable to an Unsecured Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Transmission Default Amount, shall be distributed pro rata to the Unsecured Municipal Market Participants that did not receive the full amount of their Payments as a result of such Unsecured Municipal Transmission Default Amount not being paid, up to the full amount that such Unsecured Municipal Market Participants did not receive as a result of such Unsecured Municipal Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Municipal Transmission Default Amount remains unpaid to Unsecured Municipal Market Participants on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Unsecured Municipal Transmission Default Amount remaining unpaid shall be reallocated among all of the Unsecured Municipal Market Participants receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Unsecured Municipal Market Participant defaulting on its payment obligations), pro rata based, for each Unsecured Municipal Market Participant being allocated a share of the Unsecured Municipal Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Unsecured Municipal Market Participant that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments for Transmission Charges due to such Unsecured Municipal Market participant that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Municipal Market Participant with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and an Unsecured Municipal Market Participant with $1,000 of Transmission Charges and $1,000 of Payments for Transmission Charges on its Transmission Statement for the

Transmission Default Period would be allocated an equal share of the unpaid Unsecured Municipal Transmission Default Amount under this clause (f)(ii). Each Unsecured Municipal Market Participant that received a Transmission Statement for the Transmission Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Unsecured Municipal Transmission Default Amount remaining unpaid under this clause (f)(ii). As funds attributable to an Unsecured Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Transmission Default Amount, shall be distributed to the Unsecured Municipal Market Participants pro rata based on their allocation of the Unsecured Municipal Transmission Default Amount under this clause (f)(ii), up to the full amount of such Unsecured Municipal Transmission Default Amount allocated to each such Unsecured Municipal Market Participant, with interest thereon.

(iii) An Unsecured Municipal Market Participant will not be allocated any Unsecured Municipal Transmission Default Amounts under this Section 3.4(f) for any Transmission Default Period if, at the start of the calendar year in which the applicable Transmission Default Period occurred, that Unsecured Municipal Market Participant provided the ISO with a written request to opt out of that allocation of Unsecured Municipal Transmission Default Amounts and that Unsecured Municipal Market Participant provides the ISO with additional financial assurance in the full amount of all of its "Transmission Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

g) *Reduction of Payments and Increases in Transmission Charges for Unsecured Non-Municipal Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity is an Unsecured Non-Municipal Covered Entity and (B) the procedures described in clauses (a), (b),

(c), (d), and (e) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Non-Municipal Covered Entities owed monies for the applicable Transmission Default Period, pro rata based on the Transmission Charges owed to those Unsecured Non-Municipal Covered Entities, to the extent necessary to clear its accounts for Transmission Charges due to Unsecured Non-Municipal Covered Entities by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.4(g) shall not exceed the defaulting Unsecured Non-Municipal Covered Entity's Transmission Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Non-Municipal Transmission Default Amount"). As funds attributable to an Unsecured Non-Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Transmission Default Amount, shall be distributed pro rata to the Unsecured Non-Municipal Covered Entities that did not receive the full amount of their Payments as a result of such Unsecured Non-Municipal Transmission Default Amount not being paid, up to the full amount that such Unsecured Non-Municipal Covered Entities did not receive as a result of such Unsecured Non-Municipal Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Non-Municipal Transmission Default Amount remains unpaid to Unsecured Non-Municipal Covered Entities on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Unsecured Non-Municipal Transmission Default Amount remaining unpaid shall be reallocated among all of the Unsecured Non-Municipal Covered Entities receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Unsecured Non-Municipal Covered Entity defaulting on its payment obligations), pro rata based, for each Unsecured Non-Municipal

Covered Entity being allocated a share of the Unsecured Non-Municipal Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Unsecured Non-Municipal Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments for Transmission Charges due to such Unsecured Non-Municipal Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Non-Municipal Covered Entity with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and an Unsecured Non-Municipal Covered Entity with $1,000 of Transmission Charges and $1,000 of Payments for Transmission Charges on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Unsecured Non-Municipal Transmission Default Amount under this clause (g)(ii). Each Unsecured Non-Municipal Covered Entity that received a Transmission Statement for the Transmission Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Unsecured Non-Municipal Transmission Default Amount remaining unpaid under this clause (g)(ii). As funds attributable to an Unsecured Non-Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Transmission Default Amount, shall be distributed to the Unsecured Non-Municipal Covered Entities pro rata based on their allocation of the Unsecured Non-Municipal Transmission Default Amount under this clause (g)(ii), up to the full amount of such Unsecured Non-Municipal Transmission Default Amount allocated to each such Unsecured Non-Municipal Covered Entity, with interest thereon.

(iii) An Unsecured Non-Municipal Covered Entity will not be allocated any Unsecured Non-Municipal Transmission Default Amounts under this Section 3.4(g) for any Transmission Default Period if, at the start of the calendar year in which the applicable Transmission Default Period occurred, that Unsecured Non-Municipal Covered Entity provided the ISO with a written request to opt out of that allocation of Unsecured Non-Municipal Transmission Default Amounts and that Unsecured Non-Municipal Covered Entity provides the ISO with additional financial assurance in the full amount of all of its "Transmission Obligations" under the ISO New England Financial Assurance Policy all times during that calendar year.

h) Reduction of Payments and Increases in Transmission Charges for Other Covered Entities.

(i) If and to the extent that (A) the defaulting Covered Entity is not an Unsecured Covered Entity or the Transmission Default Amount for that Covered Entity exceeds the Unsecured Municipal Transmission Default Amount or the Unsecured Non-Municipal Transmission Default Amount (referred to together herein as the "Unsecured Transmission Default Amount") for that Covered Entity and (B) the procedures described in clauses (a), (b), (c), (d), (e) and (f) or (g) (if applicable) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to those Covered Entities owed monies for Transmission Charges for that Transmission Default Period, pro rata based on the amounts owed to all Covered Entities, to the extent necessary to clear its accounts for Transmission Charges by the close of banking business on the date such Payments are due (after giving effect to clauses (f) and (g) above if applicable) (the amount of such reduction in Payments for Transmission Charges after giving effect to clauses (f) and (g) above (if applicable) is referred to herein as the "Uncovered Transmission Default Amount"). For the avoidance of doubt, the Uncovered Transmission Default Amount is equal to the Transmission Default Amount minus any Unsecured Transmission Default Amount. As funds attributable to an Uncovered Transmission Default Amount are received by the ISO (including amounts received through financial assurance provided under the ISO New England Financial Assurance Policy or through actions or proceedings

commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Transmission Default Amount, shall be distributed pro rata to the Covered Entities that did not receive the full amount of their Payments as a result of such Uncovered Transmission Default Amount not being paid, up to the full amount that such Covered Entities did not receive as a result of such Uncovered Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any amount of an Uncovered Transmission Default Amount remains unpaid to Covered Entities on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Uncovered Transmission Default Amount remaining unpaid shall be reallocated among all the Covered Entities receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Covered Entity defaulting on its payment obligations), pro rata based, for each Covered Entity being allocated a share of the Uncovered Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments due to such Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, a Covered Entity with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and a Covered Entity with $1,000 of Transmission Charges and $1,000 of Payments on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Uncovered Transmission Default Amount under this clause (h)(ii). Each Covered Entity that received a Transmission Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Uncovered Transmission Default Amount remaining unpaid under this clause (h)(ii). As funds attributable to an Uncovered Transmission Default Amount are received by the ISO

(including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Uncovered Transmission Default Amount, shall be distributed to the Covered Entities pro rata based on their allocation of the Uncovered Transmission Default Amount under this clause (h)(ii), up to the full amount of such Uncovered Transmission Default Amount allocated to each such Covered Entity, with interest thereon.

i) *Order of Settlement.*

As amounts on Transmission Default Amounts are received by the ISO, the oldest outstanding Transmission Charges will be settled first in the order of the creation of such debts.

Section 3.5 -Enforcement of Payment Obligations Against Defaulting Covered Entities. Each Covered Entity that shared in any shortfall in payments under Section 3.3 or Section 3.4 shall have an independent right to seek and obtain payment and recovery of the amount of its share of such shortfall (the "Allocated Assessment") from the defaulting Covered Entity. Each Covered Entity consents to other Covered Entities' having this independent right. Any Covered Entity that recovers any portion of its Allocated Assessment from a defaulting Covered Entity shall promptly so notify the ISO, and such Covered Entity's share of any recovery of a shortfall in payments hereunder shall be reduced by the amount of its Allocated Assessment that it recovers on its own. In addition to any amounts in default, the defaulting Covered Entity shall be liable to the ISO and each other Covered Entity for all reasonable costs incurred in enforcing the defaulting Covered Entity's obligations.

Section 3.6 – Set-Off. The ISO shall apply any amount to which any defaulting Covered Entity is or will be entitled for ISO Charges or Transmission Charges toward the satisfaction of any of that defaulting Covered Entity's debts to NEPOOL or to the ISO for ISO Charges or Transmission Charges which are incurred under the Governing Documents, including the ISO New England Financial Assurance Policy; provided that amounts due for ISO Charges will first be applied to ISO Charges then, to the extent of any excess, to Transmission Charges, and amounts due for

Transmission Charges will be first applied to Transmission Charges then, to the extent of any excess, to ISO Charges.

Section 3.7 – Notice and Suspension. Without limiting any of the other remedies described above, in the event that the ISO, in its reasonable opinion, believes that all or any part of any amount due to be paid by any Covered Entity for ISO Charges (other than NEPOOL GIS API Fees) or Transmission Charges will not be or has not been paid when due, the ISO (on its own behalf or on behalf of the Covered Entities) may (but shall not be required to) notify such Covered Entity in writing, electronically and by first class mail sent in each case to such Covered Entity's billing contact, of such payment default. If a payment default (other than a payment default relating solely to NEPOOL GIS API Fees) is not cured by 10:00 a.m. Eastern Time on the Business Day immediately following the Business Day when such payment was originally due, the ISO shall notify such Market Participant, the NEPOOL Budget and Finance Subcommittee, all members and alternates of the Participants Committee, the New England governors and utility regulatory agencies and the credit and billing contacts for all Market Participants of (i) the identity of the Covered Entity receiving such notice, (ii) whether such notice relates to a payment default, (iii) whether the defaulting Covered Entity has a registered load asset, and (iv) the actions the ISO plans to take and/or has taken in response to such payment default. In addition, the ISO will provide any additional information with respect to such payment default as may be required under the ISO New England Information Policy. If a payment default (other than a payment default relating solely to NEPOOL GIS API Fees) is not cured by 8:30 a.m., Eastern Time, of the second Business Day after the date when such payment was originally due, the defaulting Covered Entity shall be suspended pursuant to the suspension provisions of the ISO New England Financial Assurance Policy (which will apply to the defaulting Covered Entity regardless of whether it is a "Municipal Market Participant" or a "Non-Municipal Market Participant" under the ISO New England Financial Assurance Policy). Such defaulting Covered Entity shall be suspended as described in the ISO New England Financial Assurance Policy until such payment default has been cured in full. If the ISO has issued a notice that a Covered Entity has defaulted on a payment obligation and that Covered Entity subsequently cures that payment default, such Covered Entity may request the ISO to issue a notice stating such fact; provided, however, that the ISO shall not be required to issue that notice unless, in its sole discretion, the ISO determines that such payment default has been cured and such Covered Entity has no other outstanding payment defaults.

If either (x) a Covered Entity is suspended from the New England Markets as a result of a payment default as described in this Section 3.7 as a result of a payment default involving ISO Charges or (y) a Covered Entity receives more than five notices of payment defaults with respect to ISO Charges in any rolling 12-month period, then such Covered Entity shall pay a $1,000 penalty for such suspension and for each notice after the fifth notice in a rolling 12-month period. All penalties paid under this paragraph shall be deposited in the Late Payment Account.

Section 3.8– Bankruptcy Filings. In the event any Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor (the "Bankruptcy Event") and the ISO is required to return any payments made by such Covered Entity to the bankruptcy court having jurisdiction over such Bankruptcy Event, the ISO may avail itself of any emergency funding provisions in the Transmission, Markets and Services Tariff to collect the amounts returned by the ISO.

Section 3.9 – Partial Payments of Combined Invoices. If ISO Charges and Transmission Charges are included on the same Invoice and the Covered Entity pays only a portion of the Charges included in that Invoice, then the ISO shall use monies received by it from that Covered Entity (i) first to pay all amounts due from that Covered Entity to the ISO under Section IV of the Transmission, Markets and Services Tariff, to NEPOOL for Participant Expenses, and to the ISO for acting as Project Manager for the NEPOOL GIS before making any payments to any Covered Entities, then (ii) then to pay all amounts due for that Covered Entity's share, if any, of the amounts due to the NEPOOL GIS Administrator (other than NEPOOL GIS API Fees), (iii) then to pay all amounts due from that Covered Entity with respect to the Shortfall Funding Arrangement, and (iv) then, to the extent of any remaining amounts received from that Covered Entity, those amounts will be allocated to the ISO Charges and Transmission Charges on that Invoice pro rata based on the total amount of each set of Charges on that Invoice, subject to Section 3.3(l) with respect to Charges for Qualification Process Cost Reimbursement Deposits and/or Charges for NEPOOL GIS API Fees. Notwithstanding the foregoing, a partial payment of any Invoice shall be a payment default.

3.10 – Sharing of Financial Assurance. If the financial assurance(s) provided by a Covered Entity under the ISO New England Financial Assurance Policy are insufficient to effect payment of all ISO Charges and Transmission Charges that are due on the same date and which have not been

paid by that Covered Entity, the ISO shall allocate the amounts available under those financial assurance(s) as follows:

i. first to pay all amounts due from that Covered Entity to the ISO under Section IV of the Transmission, Markets and Services Tariff, to NEPOOL for Participant Expenses, and to the ISO for acting as Project Manager of the NEPOOL GIS;

ii. second, to pay all amounts due for that Covered Entity's share, if any, of the amounts due to the NEPOOL GIS Administrator (other than NEPOOL GIS API Fees);

iii. third, to pay all amounts due from that Covered Entity with respect to the Shortfall Funding Arrangement;

iv. fourth, to the Covered Entity's Charges for FTR transactions, up to the FTR Financial Assurance Requirements calculated for that Covered Entity by the ISO on the last day of the billing period for which the payment default has occurred; and

v. fifth, to the remaining unpaid ISO Charges and the unpaid Transmission Charges owed by that Covered Entity pro rata based on the total amount of each set of Charges due, subject to Section 3.3(l) with respect to Charges for Qualification Process Cost Reimbursement Deposits and/or Charges for NEPOOL GIS API Fees.

Section 3.11 – Allocation of Payment Defaults to Other Groups. In some cases, the Default Amount or the Transmission Default Amount may exceed the amounts owed to the specified Covered Entities that are to receive less than the full Payments due to them pursuant to Section 3.3(h)(i), Section 3.3(i)(i), Section 3.4(f)(i) or Section 3.4(g)(i). In such an event, the ISO will reduce the Payments due to Covered Entities pursuant to Section 3.3(j)(i) (for ISO Charges) or Section 3.4(h)(i) (for Transmission Charges) to the extent necessary for the ISO to clear its accounts for ISO Charges or Transmission Charges by the close of banking business on the date the applicable Payments are due. Any amount allocated to Covered Entities under the preceding sentence will be invoiced to and collected from the appropriate Covered Entities under Section

3.3(h)(ii), Section 3.3(i)(ii), Section 3.4(f)(ii) or Section 3.4(g)(ii) in the billing period immediately following the billing period in which that allocation occurred.

Section 3.12 – Other Rights Against Defaulting Parties. Nothing set forth in the ISO New England Billing Policy shall nullify, restrict or otherwise limit the rights and remedies of the ISO, NEPOOL and the Covered Entities against a defaulting Covered Entity that are set forth in the Governing Documents, including the ISO New England Financial Assurance Policy or otherwise, including without limitation any late payment charges or rights to terminate or limit trading rights of the defaulting Covered Entity, to the extent such rights and remedies otherwise exist.

SECTION 4 – LATE PAYMENT CHARGE; LATE PAYMENT ACCOUNT

Section 4.1 -Late Payment Charge.

(a) If a Covered Entity is delinquent two or more times within any period of 12 months in paying on time its ISO Charges, such Covered Entity shall pay, in addition to interest on each such late payment, a late payment charge for its second failure to pay on time, and for each subsequent failure to pay on time within the same 12-month period (a "Late Payment Charge") in an amount equal to the greater of (i) two percent (2%) of the total amount of such late payment or (ii) $500.00. In the case of a former Market Participant that applies again for membership in the ISO, a determination of delinquency shall be based on the Market Participant's history of payment of its ISO Charges in its last 12 months of membership.

(b) If a Covered Entity is delinquent two or more times within any period of 12 months in paying on time its Transmission Charges, such Covered Entity shall pay, in addition to interest on each such late payment, a late payment charge for its second failure to pay on time, and for each subsequent failure to pay on time within the same 12-month period (a "Transmission Late Payment Charge") in an amount equal to the greater of (i) two percent (2%) of the total amount of such late payment or (ii) $500.00. In the case of a former Market Participant that applies again for membership in the ISO, a determination of delinquency shall be

based on the Market Participant's history of payment of its Transmission Charges in its last 12 months of membership.

Section 4.2 -Late Payment Account; Transmission Late Payment Account.

(a) Interest collected on late payments of ISO Charges shall be allocated and paid to the Covered Entities to whom such late payments are due, pro rata in accordance with the amount due to each such Covered Entity. Late Payment Charges that are collected and not distributed to the Covered Entities under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy shall be deposited by the ISO into a segregated interest-bearing account (the "Late Payment Account") for disbursement in accordance with Section 3.3 of the ISO New England Billing Policy; provided, however, that in no event shall the amount in the Late Payment Account, including interest accrued thereon, at any time exceed $1,000,000 or other amount determined from time to time by the Participants Committee (the "Late Payment Account Limit"). Any amount in the Late Payment Account (including interest thereon) in excess of the Late Payment Account Limit shall be distributed to the Market Participants, no more frequently than quarterly, pro rata based on their ISO Charges in the month preceding the month in which such distribution is to be made; provided, however that no amount from the Late Payment Account shall be distributed to any Market Participant in payment default at the time of such distribution.

(b) Interest collected on late payments of Transmission Charges shall be allocated and paid to the Covered Entities to whom such late payments are due, pro rata in accordance with the amount due to each such Covered Entity. Transmission Late Payment Charges that are collected and not distributed to the Covered Entities under the ISO New England Billing Policy shall be deposited by the ISO into a segregated interest-bearing account (the "Transmission Late Payment Account") for disbursement in accordance with Section 3.4 of the ISO New England Billing Policy; provided, however, that in no event shall the amount in the Transmission Late Payment Account, including interest accrued thereon, at any time exceed $1,000,000 or other amount determined from time to time by the Participants

Committee (the "Transmission Late Payment Account Limit"). Any amount in the Transmission Late Payment Account (including interest thereon) in excess of the Transmission Late Payment Account Limit shall be distributed to the Market Participants, no more frequently than quarterly, pro rata based on their Transmission Charges in the month preceding the month in which such distribution is to be made; provided, however that no amount from the Transmission Late Payment Account shall be distributed to any Market Participant in payment default at the time of such distribution.

SECTION 5 – SHORTFALL FUNDING ARRANGEMENTS: PAYMENT DEFAULT SHORTFALL FUND

Section 5.1 – Purpose and Creation of the Shortfall Funding Arrangement and the Payment Default Shortfall Fund. The ISO, acting in consultation with the NEPOOL Budget and Finance Subcommittee and NEPOOL's Independent Financial Advisor, will arrange separate financing (the "Shortfall Funding Arrangement") that can be used to make up any non-congestion related differences between ISO Charges received on Invoices and amounts due for ISO Charges in any week and as set forth in Sections 3.3 and 3.4. The Shortfall Funding Arrangement may be effected through third-party financing, through the creation of a special purpose funding entity, through Participant-provided funds or through some other arrangement agreed upon by the ISO, the NEPOOL Budget and Finance Subcommittee and NEPOOL's Independent Financial Advisor. If and to the extent that, at any time, the Shortfall Funding Arrangement is not available (because, solely for example, it has not been arranged, it does not have sufficient funds available, it has expired or it has been terminated prior to its maturity), the ISO shall create a Payment Default Shortfall Fund that will provide for such non-congestion related difference between ISO Charges received on Invoices and amounts due for ISO Charges in any week and for payments in accordance with Section 3.3 and 3.4. The Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund shall be in addition to and not a replacement for the Late Payment Account or the Transmission Late Payment Account described above.

Section 5.2 -Participant Rights with respect to a Participant Financial Payment Default Shortfall Fund. To the extent that the Payment Default Shortfall Fund is in existence at any time, each Participant funding the Payment Default Shortfall Fund at such time would retain title to its share of amounts in the Payment Default Shortfall Fund and any interest accrued on those amounts on a

pro rata basis based on the funds in the Payment Default Shortfall Fund provided by it. Each Participant will receive a monthly report that will identify the amount of funds in the Payment Default Shortfall Fund that belong to that Participant and the amount of interest accrued thereon. As Participants withdraw from or otherwise terminate membership in the ISO, the ISO would pay to such Participants their share, if any, of the amounts in the Payment Default Shortfall Fund, with interest. To the extent that the balance in the Payment Default Shortfall Fund exceeds the Required Balance, the excess will be refunded to Participants on a quarterly basis pro rata based on their share of the funds in the Payment Default Shortfall Fund.

Section 5.3 – Available Amount of Shortfall Funding Arrangement; Initial Funding of the Payment Default Shortfall Fund. The available amount of the Shortfall Funding Arrangement, combined with any amount on deposit in the Payment Default Shortfall Fund, shall be equal to the amount of a hypothetical Invoice at the 97th percentile of the average amounts due on Invoices rendered to Market Participants over the six calendar months preceding the calculation or a lesser amount as set by the ISO from time to time in consultation with the NEPOOL Budget and Finance Subcommittee (the "Required Balance"), which amount shall be calculated and adjusted by the ISO on a quarterly basis. To the extent that on any Business Day immediately following the date on which Payments for Non-Hourly Charges are due, either the Shortfall Funding Arrangement has not been established or the available amount of the Shortfall Funding Arrangement is less than the Required Balance, the ISO shall establish the Payment Default Shortfall Fund, and the Participants shall be responsible for initially funding the Payment Default Shortfall Fund in an amount equal to the Required Balance less the available amount, if any, of the Shortfall Funding Arrangement on such date (the "Participant Required Balance"). The ISO, in consultation with NEPOOL's Independent Financial Advisor, shall notify the Market Participants promptly if they believe that the available amount of the Shortfall Funding Arrangement is not, or is reasonably likely not to be, at least equal to the Required Balance, and the ISO will endeavor to arrange a supplement to any existing Shortfall Funding Arrangement at least to the extent required to fund such shortfall. The Market Participant Required Balance shall initially be funded by the Market Participants pro rata in accordance with the methodology used for the shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on Charges and Payments due over the three months immediately preceding the establishment of the Payment Default Shortfall Fund). A Participant's Payment Default Shortfall Fund payment obligation shall be identified as a separate line item on its Statements and Transmission Statements.

Section 5.4 Continued Shortfall Fund Funding Obligations; Payments on Shortfall Funding Arrangement.

(a) The ISO will reallocate the Market Participants' overall obligation with respect to the amounts in the Payment Default Shortfall Fund, if any, annually on each anniversary of the Effective Date in accordance with the methodology used for shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on the Charges and Payment due in the preceding calendar year), with payments from and refunds to Market Participants that have underfunded or overfunded, respectively, the Payment Default Shortfall Fund based on that annual reallocation.

(b) If the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund (the "Total Available Amount") drops below 90 percent of the Required Balance at any time because of Market Participant terminations (but not because of draws on the Shortfall Funding Arrangement or the Payment Default Shortfall Fund or adjustments to the Required Balance), each Market Participant would be required to contribute a share of the funds needed to restore the Total Available Amount to the Required Balance. A Market Participant's pro rata share of that obligation would be determined in accordance with the methodology used for shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on Charges and Payments due for the three months immediately preceding the date of that funding).

(c) If (i) the ISO draws on the Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund and the amount drawn, together with interest and fees thereon, is not replaced through payments on the payment default by the date on which the ISO next issues an Invoice that includes Non-Hourly Charges, or (ii) the Required Balance is increased as a result of quarterly adjustments, that next Invoice for Non-Hourly Charges will include a charge for Covered Entities necessary to restore the Total Available Amount to the Required Balance. That charge will be allocated among the Covered Entities according to the methodology used for the shortfall allocation process in Section 3.3(j)(ii) and

Section 3.4(h)(ii) of the ISO New England Billing Policy with respect to the specific payment default. If payments on a payment default are received after the amount drawn from the Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund for that payment default has been refunded, the amount of the payment default so received shall be allocated and paid to the Covered Entities providing that funding according to the methodology of Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy.

(d) In addition to the other obligations described in this Section 5.4, each Market Participant shall be charged a pro rata share of all interest, fees and other expenses incurred in connection with the Shortfall Funding Arrangement to the extent that such interest, fees and expenses are not paid by a Covered Entity with respect to a payment default. The pro rata allocation of fees and expenses described herein shall be made on the same basis as set forth in Section 5.4(c) above. A Market Participant's obligation with respect to the Shortfall Funding Arrangement shall be identified as a separate line item on its statements.

(e) Without limiting the generality of Section 3.3 and Section 3.4, to the extent that a Covered Entity fails to pay an Invoice, requiring a draw on the Shortfall Funding Arrangement, that Covered Entity shall be required to pay the amount of such draw, plus any interest accrued thereon and premium or other fees or expenses with respect thereto.

Section 5.5 -Payment Default Shortfall Fund Account. Funds collected as Market Participant contributions to the Payment Default Shortfall Fund shall be deposited by the ISO into a segregated interest-bearing account.

SECTION 6 -BILLING DISPUTE PROCEDURES.

Section 6.1 -Requested Billing Adjustments Eligible for Resolution under Billing Dispute Procedures. Any Covered Entity may dispute the amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice (a "Disputed Amount"). Such party (a "Disputing Party") shall seek to recover such Disputed Amount, including accrued interest, pursuant to this Section 6, by first submitting a request for billing adjustment to the ISO

(a "Requested Billing Adjustment" or "RBA") in accordance with the procedures provided in this Section 6. A Disputing Party may seek resolution of a Requested Billing Adjustment under this Section 6 concerning any Disputed Amount resulting from the determination of a market clearing price or Transmission, Markets and Services Tariff rate by the ISO that allegedly either violates or is otherwise inconsistent with the Transmission, Markets and Services Tariff, or results from error by the ISO, and provided that a request for a correction of a Meter Data Error shall not be considered a Requested Billing Adjustment for purposes of the ISO New England Billing Policy, and requests for corrections of Meter Data Errors will be handled exclusively through the procedures set out in Market Rule 1. Notwithstanding the foregoing, a Requested Billing Adjustment must involve a requested change in an amount owed or believed to be owed in a Remittance Advice that is not covered by another alternative dispute resolution procedure under the Transmission, Markets and Services Tariff. Furthermore, a Requested Billing Adjustment must not involve Disputed Amounts paid on an Invoice for Non-Hourly Charges pursuant to the ISO New England Financial Assurance Policy, provided, however, that this provision shall not preclude a Disputing Party from submitting a Requested Billing Adjustment for a Disputed Amount on a fully paid monthly Invoice for Non-Hourly Charges which has been paid pursuant to an Invoice for Non-Hourly Charges in that month.

Section 6.2 -Effect of the ISO New England Billing Policy on Rights of Market Participant, PTO, or Non-Market Participant Transmission Customer with Respect to a Disputed Amount. Except as otherwise set forth in this Section 6.2, nothing in this Section 6 shall in any way abridge the right of any Covered Entity to seek legal or equitable relief under the Federal Power Act and/or any other applicable laws with respect to any Disputed Amount. Prior to commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction to resolve the dispute which is the subject of the Requested Billing Adjustment, the Disputing Party must first submit the Requested Billing Adjustment to the ISO for review pursuant to Section 6.3 of the ISO New England Billing Policy.

Section 6.3 – ISO Review of Requested Billing Adjustment.

Section 6.3.1 – Submission of Requested Billing Adjustment to the ISO; Required Contents of Requested Billing Adjustment. A Disputing Party shall submit a Requested Billing Adjustment in writing to Participant Support and Solutions at the ISO via its support system. A Requested Billing Adjustment will be deemed received once an acknowledgement and/or a case number has

been assigned and transmitted to the Disputing Party. In its Requested Billing Adjustment, the Disputing Party must specify: (a) the Disputed Amount at issue, (b) the instance of alleged error at issue, including a statement detailing the specific provisions of all applicable governing documents that support the Requested Billing Adjustment, and (c) the specific person or persons to whom all communications to the Disputing Party regarding the Requested Billing Adjustment are to be addressed. A Disputing Party must submit its Requested Billing Adjustment within three months of the date that the Invoice or Remittance Advice containing the Disputed Amount was issued by the ISO unless the Disputing Party could not have reasonably known of the existence of the alleged error within such time.

Section 6.3.2 – Notice of ISO Review of Requested Billing Adjustment. Within three Business Days of the receipt ISO Participant Support and Solutions by of a Requested Billing Adjustment, 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 Requested Billing Adjustment ("Notice of RBA"), including, subject to the protection of Confidential Information, the specifics of the Requested Billing Adjustment. The Notice of RBA shall identify a specific representative of the ISO to whom all communications regarding the Requested Billing Adjustment are to be sent.

Section 6.3.3 – ISO Review of Requested Billing Adjustments. The ISO shall complete its review of a Requested Billing Adjustment received pursuant to Section 6.3 within twenty (20) Business Days of the date the ISO distributes the Notice of RBA. To the extent that either party makes such a request and both parties agree to such request, the ISO and Disputing Party may meet or otherwise confer during this period in an effort to resolve the Requested Billing Adjustment.

Section 6.3.4 – Comment Period. Any Covered Entity which desires to do so, or NEPOOL if it desires to do so, may submit to the ISO's designated representative, on or before the tenth (10th) Business Day following the date the ISO distributes the Notice of RBA, written comments to the ISO with respect to the Requested Billing Adjustment. Any such comments are to be transmitted simultaneously to the Disputing Party. The Disputing Party may respond to any such comments by submitting a written response to the ISO's designated representative and to the commenting party on or before the fifteenth (15th) Business Day following the date the ISO distributes the Notice of RBA. In determining the action it will take with respect to the Requested Billing Adjustment, the ISO shall consider the written response filed by the Disputing Party. The ISO

may but is not required to consider any written comments that are filed by any other interested party.

Section 6.3.5 – ISO Action on Requested Billing Adjustment. The ISO shall provide to the Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee a written decision (the "RBA Decision") accepting or denying a Requested Billing Adjustment received pursuant to this Section 6.3 within twenty (20) Business Days of the date the ISO distributes the Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO. The ISO shall provide written notice and a copy of each RBA Decision to each Covered Entity either eligible for reimbursement, denied reimbursement of a Disputed Amount or required to provide reimbursement of a Disputed Amount because of an RBA Decision (hereafter referred to as an "Affected Party" or the "Affected Parties") within five (5) Business Days of the date the RBA Decision is rendered. In providing such notice to any Affected Party required to provide reimbursement of a Disputed Amount, the ISO shall specify the amount to be reimbursed by such Affected Party and the calculations supporting the determination of such reimbursement amount. Subsequent to the provision of the written notice of the RBA Decision as set forth above, the ISO shall provide each Affected Party with respect to that RBA Decision a monthly report of the status of such RBA Decision within the dispute resolution process set forth in this Section 6, including a statement of the accounting treatment of the disputed amount owed by or to that Affected Party with respect to that RBA Decision in accordance with the most recent decision issued pursuant to Sections 6.3.6 or 6.4 of the ISO New England Billing Policy, whichever applies, with respect to that RBA Decision. For purposes of this Section, the term "Affected Parties" shall also include the Disputing Party.

Section 6.3.6 – Finality of ISO Action on Requested Billing Adjustment. Except as otherwise provided in this Section 6.3.6, the RBA Decision shall become final and binding on the Affected Parties and shall not be appealable in any forum on the twenty-first (21st) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above. The RBA Decision shall not become final or binding if, on or before the twentieth (20th) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above, an Affected Party has appealed the RBA Decision by commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction over the dispute, or has filed an appeal pursuant to Section 6.4 of the ISO New England Billing Policy. If a proceeding is commenced before the Commission or

other regulatory or judicial authority with jurisdiction over the dispute, the Affected Party commencing that proceeding shall simultaneously transmit a copy of its initial pleading in that proceeding to the ISO's designated representative for that particular RBA Decision, and to the Chair of the NEPOOL Budget and Finance Subcommittee and shall also submit to the ISO's designated representative for that particular RBA a copy of the final order or decision in that proceeding resolving the dispute. If any such appeal is filed pursuant to Section 6.4 of the ISO New England Billing Policy, the RBA Decision shall have no force or effect unless or until it is affirmed or upheld upon completion of the appeal process selected by the Affected Party and as provided for in the ISO New England Billing Policy.

Section 6.4 – Right of Affected Party to Review of ISO RBA Decision by AAA.

Section 6.4.1 – Right to Further Review. An Affected Party may seek review of an RBA Decision by an independent third party neutral by submitting, on or before the twentieth (20th) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above, a request for arbitration of the Requested Billing Adjustment with the American Arbitration Association ("AAA"). At the same time that it submits its request to the AAA, the Affected Party commencing any such review of an RBA Decision shall transmit its request for arbitration: (i) to the ISO's designated representative for that particular RBA Decision; and (ii) to each of the Affected Parties; and (iii) to the Chair of the NEPOOL Budget and Finance Subcommittee. The ISO and any Affected Party shall be joined as parties to the arbitration. NEPOOL and other Covered Entities shall be permitted to intervene in the arbitration if they desire to do so.

Section 6.4.2 – Finality of the AAA Neutral's Decision. Except as otherwise provided in this Section 6.4.2, the written, final decision of the AAA neutral shall become final and binding on the Affected Parties, including the ISO, and shall not be appealable in any forum on the twenty-first (21st) Business Day after the date on which the final decision of the AAA neutral was issued. The final decision of the AAA neutral shall not become final or binding if on or before the twentieth (20th) Business Day after the date on which the final decision of the AAA neutral was issued, an Affected Party or Parties or the ISO has appealed the final decision of the AAA neutral by commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction over the dispute. If any such appeal is filed, the final decision of the AAA

neutral shall have no force or effect unless or until it is affirmed or upheld upon completion of the appeal process.

Section 6.5 – Access to Confidential Information. Information that is deemed confidential pursuant to the ISO New England Information Policy in the possession, custody or control of the ISO concerning the dollar amount in Invoices or Remittance Advices issued by the ISO ("Confidential Information") shall be made available under these billing dispute procedures only to "Dispute Representatives" who have executed a confidentiality agreement in accordance both with this Section 6.5 and the ISO New England Information Policy in the form of Attachment 1 hereto ("Confidentiality Agreement"). A copy of the executed Confidentiality Agreement for a Dispute Representative shall be provided to the ISO prior to the disclosure of any Confidential Information to said Dispute Representative. Confidential Information shall not be disclosed to anyone other than in accordance with this Section 6.5, and shall be used only in connection with the billing dispute procedures provided under this Section 6.

a) *Potential Disputing Parties' Right of Access to Confidential Information.* A Market Participant, PTO or Non-Market Participant Transmission Customer that is a potential Disputing Party is entitled to obtain access to Confidential Information for its Dispute Representative, if and only if, it can demonstrate to the ISO that such access is required to determine if it has a substantive basis for filing a Requested Billing Adjustment with the ISO. Such demonstration by a potential Disputing Party, at a minimum, shall include: the information submitted to ISO Participant Support and Solutions required in Section 6.3.1; and, why lack of access to Confidential Information prevents the potential Disputing Party from determining if it has a substantive basis for filing such a Requested Billing Adjustment. A potential Disputing Party shall submit a request for access to Confidential Information in writing to the ISO (an "Information Request"). The ISO shall evaluate and respond to such an Information Request within ten (10) days of the receipt of the Information Request, and where the need for access to Confidential Information is demonstrated in accordance with the above, shall provide access to such Confidential Information within fifteen (15) days of the receipt of the Information Request.

b) *Affected Parties Right of Access to Confidential Information*. If the RBA Decision is submitted to the AAA for resolution pursuant to Section 6.4, then for purposes of that AAA proceeding a Market Participant or Non-Market Participant Transmission Customer that is an Affected Party is entitled to obtain access to Confidential Information for its Dispute Representative if, and only if, it can demonstrate to the AAA Neutral that such access is required to protect its financial interests with respect to review of an RBA Decision pending before the Neutral. An Affected Party shall submit a request for access to Confidential Information concerning an RBA Decision within the timeframes established by the Neutral. The Neutral shall have the authority to enter such orders as may be necessary to protect the Confidential Information, in accordance with applicable ISO policies including but not limited to the ISO New England Information Policy.

c) *Dispute Representatives.* Dispute Representatives shall be limited to the AAA Neutral(s), Covered Entities and third parties retained by and/or in-house legal counsel of the AAA or Covered Entities; provided, however, that Confidential Information may not be disclosed to a Dispute Representative to the extent the disclosure is prohibited by Order 889. A Dispute Representative may disclose Confidential Information to any other Dispute Representative as long as the disclosing Dispute Representative and the receiving Dispute Representative each have executed a Confidentiality Agreement. In the event that any Dispute Representative to whom Confidential Information is disclosed ceases to be engaged in a matter under these billing dispute procedures, or is no longer qualified to be a Dispute Representative under this Section, access to Confidential Information by that person, or persons, shall be terminated and all such Confidential Information received by that party shall be returned to the ISO or destroyed to the satisfaction of the ISO. Even if no longer engaged as a Dispute Representative under this Section, every person who has executed a Confidentiality Agreement shall continue to be bound by the provisions of this Section and such Confidentiality Agreement. All Dispute Representatives are responsible for ensuring that persons under their supervision or control comply with this Section and the Confidentiality Agreement.

d) *Maintenance of Confidential Information.* All copies of all documents and materials containing Confidential Information shall be maintained by Dispute Representatives at all times in a secure place in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Section. Such documents and material shall be marked PROTECTED CONFIDENTIAL INFORMATION and shall be maintained under seal and provided only to Dispute Representatives as are authorized to examine and inspect such Confidential Informational. Dispute Representatives shall provide to the ISO a list of those persons under the supervision and/or control of the Dispute Representative who are entitled to receive Confidential Information. Dispute Representatives shall take all reasonable precautions to ensure that Confidential Information is not distributed to unauthorized persons.

e) *ISO Right to Object to Access to Confidential Information*. Nothing in this Section shall be construed as precluding the ISO from objecting to providing any party access to Confidential Information on any legal grounds other than those provided under the ISO New England Information Policy, as it may be amended time to time.

SECTION 7 -WEEKLY BILLING PRINCIPLES FOR NON-HOURLY CHARGES.

The ISO shall administer weekly billing arrangements for Non-Hourly Charges and Transmission Charges that have been effected in special circumstances pursuant to the ISO New England Financial Assurance Policy according to the following principles:

Section 7.1 - Weekly Invoices. The ISO shall issue weekly Invoices for such Non-Hourly Charges and such Transmission Charges to any Market Participant or Non-Market Participant Transmission Customer for which such a weekly billing arrangement has been established to the extent such Market Participant's or Non-Market Participant Transmission Customer's Non-Hourly Charges and Transmission Charges exceed the Payments due to it for Non-Hourly Charges and Transmission Charges, respectively, for the current billing week. Such weekly Invoices for Non-Hourly Charges and for Transmission Charges would be issued and due at the same times as one of the twice weekly Invoices for Hourly Charges as determined by the ISO. Remittance Advices for Non-Hourly Charges and for Transmission Charges for such Market

Participants and Non-Market Participant Transmission Customers will still be issued monthly, in accordance with the procedures set forth above.

Section 7.2 -Basis for Billing. The amounts due from such Market Participant or Non-Market Participant Transmission Customer on weekly Invoices for Non-Hourly Charges and Transmission Charges shall be based on estimates derived by pro-rating the most recent final monthly Statements and Transmission Statements issued for such Market Participant or Non-Market Participant Transmission Customer.

Section 7.3 -Monthly Reconciliation. In connection with each monthly billing cycle, the ISO shall reconcile the sum of the weekly Invoices for Non-Hourly Charges and for Transmission Charges issued with the normal monthly billing quantities for such Non-Hourly Charges and Transmission Charges calculated for the Market Participant or Non-Market Participant Transmission Customer. The ISO shall perform a true-up of any amounts owed or due on the following weekly Statements or monthly Transmission Statements.

Section 7.4 – FTR-Only Customers. FTR-Only Customers are not eligible for weekly billing arrangements for Non-Hourly Charges.

Re: Requested Billing Adjustment _____

CONFIDENTIALITY AND NONDISCLOSURE AGREEMENT

The ISO ("Provider") agrees to make available, pursuant to Section 6 of the ISO New England Billing Policy, to _____ ("Recipient") confidential and proprietary information (Confidential Information") relevant to resolution of the Requested Billing Adjustment _____ and any appeals thereof as provided for in said Section 6.

1. Any information provided to the Recipient and labeled "Confidential Information" by Provider shall be confidential subject to this Agreement.
2. The Confidential Information is received by Recipient in confidence.
3. The Confidential Information shall not be used or disclosed by the Recipient except in accordance with the terms contained herein, with Section 5 of the ISO New England Billing Policy and with the ISO New England Information Policy.
4. Only individuals who are Dispute Representatives as that term is defined in Section 6 of the ISO New England Billing Policy, and not entities, may be Recipients of Confidential Information under this paragraph. By executing this Agreement, each Recipient certified that he/she meets the requirements of this Agreement.
5. The following conditions apply to each Recipient:
    a. Each Recipient will receive one (1) numbered, controlled copy of the Confidential Information. The Recipient will not make any copies thereof or provide the Confidential Information to any individual or entity except one who has executed and delivered an Agreement identical to this Agreement to the Provider.
    b. The Recipient shall maintain a log of all persons granted access to the Confidential Information.
    c. The Recipient, by signing this Agreement acknowledges that he/she may not in any manner disclose the Confidential Information to any person, and that he/she may not use the Confidential Information for the benefit of any person except in this proceeding and in accordance with the terms of this Agreement, Section 6 of the ISO New England Billing Policy and the ISO New England Information Policy.
    d. The Recipient acknowledges that any violation of this Agreement may subject the Recipient to civil actions for violation thereof.
    e. Within thirty (30) days of the final decision issued with respect to the Requested Billing Adjustment terminating all appeals with respect to this Requested Billing Adjustment, Recipient shall return the Confidential Information to Provider.

PROVIDER:	RECIPIENT:
By: _____	By:_____
Dated:_____	Dated:_____

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III.15.7.1.5 Demand Capacity Resources with Capacity Supply Obligations

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III.15.9 Information Publication and Reporting

III.13.7. Performance, Payments and Charges in the FCM.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1.

III.13.7.1.1. Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.13.7.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(a) **Forward Capacity Auction**. For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated

with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

(d) **Substitution Auctions.** For a resource whose offer or bid has cleared in a substitution auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the substitution auction clearing price. Notwithstanding the foregoing, the monthly capacity charge for a demand bid cleared at a substitution auction clearing price above its bid price shall be calculated using its bid price.

III.13.7.1.3. Export Capacity.

If there are any Export Bids or Administrative Export De-List Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows.

Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-List Bid]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located= [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.5.2.

III.13.7.1.4. [Reserved.]

III.13.7.2 Capacity Performance Payments.

III.13.7.2.1 Definition of Capacity Scarcity Condition.

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.13.7.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition

shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource or Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures, the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.13.7.2.2(c), for any On-Peak Demand Resource or Seasonal Peak Demand Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.13.7.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(i) A Demand Response Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource

was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource's Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource's Actual Capacity Provided shall not be less than zero.

(ii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

(e) A Distributed Energy Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Metered Quantity for Settlement and Reserve Quantity for Settlement of all the components of its constituent Distributed Energy Resource Aggregations; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Based on the Real-Time operational coordination, the resource must follow any distribution system limitation and update its physical parameters accordingly. The Actual Capacity Provided cannot be less than zero.

(i) The Real-Time demand reduction of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled

curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource or Demand Response Distributed Energy Resource Aggregation does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

provided, however, that the Capacity Balancing Ratio shall not exceed a value of 1.0.

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.13.7.2.A.2 in the New England Control Area during the interval.

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.13.7.2.A.2 in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.13.7.2.A.2 in the Capacity Zone during the interval.

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

III.13.7.2.4 Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero)

and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a Seasonal Peak Demand Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025, the Capacity Performance Payment Rate shall be $5455/MWh. For the period beginning on June 1, 2025 and ending on August 31, 2026, the Capacity Performance Payment Rate shall be $9337/MWh. Thereafter, the Capacity Performance Payment Rate shall be $3500/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.13.7.2.6 Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.13.7.2.A System-Backed Export Charges.

III.13.7.2.A.1 System-Backed Exports.

A System-Backed Export is an External Transaction submitted in accordance with Section III.1.10.7 or Section III.1.10.7.A to export internal energy out of the New England Control Area by a Market Participant in the Real-Time Energy Market: (1) that is not associated with a generator; or (2) for External Transactions associated with a generator, for which the megawatt amount of the External Transaction sale(s) associated with the generator is greater than the sum of the resource's energy output plus the resource's Reserve Quantity For Settlement.

III.13.7.2.A.2 Calculation of System-Backed Export Charges.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a System-Backed Export Charge: (1) for External Transactions associated with a generator, for each resource that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval; and (2) for External Transactions not associated with a generator, for each Market Participant that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval. For each five-minute interval, the System-Backed Export Charge shall be equal to the net System-Backed Export value, calculated in accordance with the formulas set forth below, multiplied by the Capacity Performance Payment Rate, as defined in Section III.13.7.2.5.

For External Transactions associated with a generator,

net System-Backed Export value = the lesser of (the energy output of the generator in the interval + the Reserve Quantity for Settlement of the generator in the interval – the hourly integrated delivered MW for the External Transaction sale(s) associated with the generator) or 0

System-Backed Export Charge = net System-Backed Export value × Capacity Performance Payment Rate

For External Transactions not associated with a generator,

net System-Backed Export value = the lesser of (the hourly integrated delivered MW for the External Transaction purchase(s) of the Market Participant – the hourly integrated delivered MW for the External Transaction sale(s) of the Market Participant) or 0

System-Backed Export Charge = net System-Backed Export value × Capacity Performance Payment Rate

Unless otherwise expressly stated, a System-Backed Export Charge shall not be treated as a Capacity Performance Payment under the Tariff.

III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below.

III.13.7.3.1 Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month (or, in the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource's Capacity Supply Obligation for the Obligation Month).

III.13.7.3.2 Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [3 months x (FCAcp – FCAsp) – (12 months x FCAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCAcp = the Capacity Clearing Price for the relevant Forward Capacity Auction.

FCAsp = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.13.7.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply

Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.13.7.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.13.7.3.2(b).

III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments and System-Backed Export Charges.

For Capacity Scarcity Conditions, as described in Section III.13.7.2.1, the ISO shall allocate deficient or excess Capacity Performance Payments and System-Backed Export Charges as described in subsections (a), (b), and (c) below.

(a) If the sum of all Capacity Performance Payments and System-Backed Export Charges to all resources subject to a Capacity Scarcity Condition in an Obligation Month is positive, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the deficiency shall be charged to resources in proportion to the sum of each such resource's positive Capacity Performance Score for the Obligation Month.

(b) If the sum of all Capacity Performance Payments and System-Backed Export Charges to all resources subject to a Capacity Scarcity Condition in an Obligation Month is negative, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the excess shall be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess shall be further allocated to other resources in the same manner as described in this Section III.13.7.4(b).

(c) If a deficiency of Capacity Performance Payments exists due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the deficiency shall be charged to all resources subject to a Capacity Scarcity Condition in an Obligation Month that have not reached their stop-loss limit (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. If the charge described in Section

III.13.7.4(a) or the charge described in this Section III.13.7.4(c) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss limit described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(c).

III.13.7.5. Charges to Market Participants with Capacity Load Obligations.

III.13.7.5.1. Calculation of Capacity Charges Prior to June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning prior to June 1, 2022. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month may also receive a failure to cover credit equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone, and; (b) the sum of all failure to cover charges in the Capacity Zone calculated pursuant to Section III.13.3.4(b), divided by total Capacity Load Obligation in the Capacity Zone.

III.13.7.5.1.1. Calculation of Capacity Charges On and After June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning on or after June 1, 2022. For purposes of this Section III.13.7.5.1.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in subsection (b) of Sections III.13.7.5.1.1.1 through III.13.7.5.1.1.9 will be divided by the number of days in the month to derive a daily settlement value.

III.13.7.5.1.1.1 Forward Capacity Auction Charge.

The FCA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone FCA Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone FCA Costs, for each Capacity Zone, are the Total FCA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total FCA Costs are the sum of, for all Capacity Zones, (i) Capacity Supply Obligations in each zone (the total obligation awarded to or shed by resources in the Forward Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.13.7.5.1.1.6 and excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) multiplied by the applicable clearing price from the auction in which the obligation was awarded to (or shed by) the resource, and (ii) the difference between the bid price and the substitution auction clearing price that was not included in the capacity charge pursuant to the second sentence of Section III.13.7.1.1(d). Capacity Supply Obligations awarded to Proxy De-List Bids in the primary auction, or shed by demand bids entered into the substitution auction on behalf of a Proxy De-List Bid, are excluded from Total FCA Costs.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.1.1.2 Annual Reconfiguration Auction Charge.

The total annual reconfiguration auction charge, for each Capacity Zone and each associated annual reconfiguration auction, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone Annual Reconfiguration Auction Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone Annual Reconfiguration Auction Costs, for each Capacity Zone, are the Total Annual Reconfiguration Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total Annual Reconfiguration Auction Costs are the sum, for all Capacity Zones and each associated annual reconfiguration auction, of the product of the Capacity Supply Obligations acquired through the annual reconfiguration auction in each zone (adjusted for any obligations procured in the annual reconfiguration auction that are subsequently terminated pursuant to Section III.13.3.4A) and the zonal annual reconfiguration auction clearing price, minus the sum, for all Capacity Zones, of the product of the amount of any Capacity Supply Obligation shed through the annual reconfiguration auction in each zone and the applicable annual reconfiguration auction clearing price.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.1.1.3. Monthly Reconfiguration Auction Charge.

The monthly reconfiguration auction charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total Monthly Reconfiguration Auction Costs divided by Total Zonal Capacity Obligation.

Where

Total Monthly Reconfiguration Auction Costs are the sum of, for all Capacity Zones, the product of Capacity Supply Obligations acquired through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price, minus the sum of, for all Capacity Zones, any Capacity Supply Obligations shed through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price.

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.4. HQICC Capacity Charge.

The HQICC capacity charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total HQICC Credits divided by Total Capacity Load Obligation.

Where

Total HQICC credits are the product of HQICCs multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone in which the HQ Phase I/II external node is located.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.5. Self-Supply Adjustment.

The self-supply adjustment is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) the Self-Supply Variance divided by Total Capacity Load Obligation.

Where

Self-Supply Variance is the difference between foregone capacity payments and avoided capacity charges associated with designated self-supply quantities.

Foregone capacity payments to Self-Supplied FCA Resources are the sum, for all Capacity Zones, of the product of the zonal Capacity Supply Obligation (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) designated as self-supply, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Avoided capacity charges are the sum, for all Capacity Zones, of the product of any designated self-supply quantities multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone associated with the designated self-supply quantity.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.6. Intermittent Power Resource Capacity Adjustment.

The Intermittent Power Resource capacity adjustment in a winter season for the Obligation Months from October through May is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) the Intermittent Power Resource Seasonal Variance divided by Total Zonal Capacity Obligation.

Where

Intermittent Power Resource Seasonal Variance is the difference between the FCA payments for Intermittent Power Resource in the Obligation Month and the base FCA payments for Intermittent Power Resources.

FCA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to or shed by Intermittent Power Resources in the Forward Capacity Auction process for the Obligation Month pursuant to Section III.13.2.7.6 or Section III.13.2.8.1.1 (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Base FCA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the FCA Qualified Capacity procured from or shed by Intermittent Power Resources in the Forward Capacity Auction process (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Total Zonal Capacity Obligation is the total Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.7. Multi-Year Rate Election Adjustment.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

Zonal Multi-Year Rate Election Costs is the sum, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public

Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, multiplied by the Zonal Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation and divided by the Total Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning prior to June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

Zonal Multi-Year Rate Election Costs is the sum in each Capacity Zone, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period.

III.13.7.5.1.1.8 CTR Transmission Upgrade Charge.

The CTR transmission upgrade charge is: (a) the Capacity Load Obligation in the Capacity Zones to which the applicable interface limits the transfer of capacity, multiplied by (b) Zonal CTR Transmission Upgrade Cost divided by Zonal Capacity Obligation.

Where

Zonal CTR Transmission Upgrade Cost for each Capacity Zone to which the interface limits the transfer of capacity is the amount calculated pursuant to Section III.13.7.5.4.4 (f), multiplied by the Zonal Capacity Obligation and divided by the sum of the Zonal Capacity Obligation for all Capacity Zones to which the interface limits the transfer of capacity.

III.13.7.5.1.1.9 CTR Pool-Planned Unit Charge.

The CTR Pool-Planned Unit charge is: (a) the total Capacity Load Obligation in all Capacity Zones less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5, multiplied by (b) CTR Pool-Planned Unit Cost divided by Total Zonal Capacity Obligation less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5.

Where

The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.13.7.5.4.5 (b).

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.10. Failure to Cover Charge Adjustment.

The failure to cover charge adjustment, for each Capacity Zone, is (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Failure to Cover Charges divided by Total Capacity Load Obligation.

Where:

Zonal Failure to Cover Charges are the product of: (1) the sum, for all Capacity Zones, of the failure to cover charges calculated pursuant to Section III.13.3.4(b), and; (2) the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price as determined pursuant to Section III.13.3.4.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.2. Calculation of Capacity Load Obligation and Zonal Capacity Obligation.
The ISO shall assign each Market Participant a share of the Zonal Capacity Obligation prior to the commencement of each Obligation Month for each Capacity Zone established in the Forward Capacity Auction pursuant to Section III.13.2.3.4. The Zonal Capacity Obligation of a Capacity Zone that contains a nested Capacity Zone shall exclude the Zonal Capacity Obligation of the nested Capacity Zone.

Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals for Capacity Commitment Periods beginning prior to June 1, 2022 and excluding any additional obligations awarded to Intermittent Power Resources pursuant to Section III.13.2.7.6 that exceed the FCA Qualified Capacity procured in the Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022) plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022) to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022).

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with the receipt of electricity from the grid by Storage DARDs for later injection of electricity back to the grid; when all load of a Distributed Energy Resource Aggregation participating as a Storage DARD is load associated with the receipt of electricity from the grid for later injection of electricity back to the grid; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as a discrete Load Asset and is exclusively related to an Alternative Technology Regulation Resource following AGC Dispatch Instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A Market Participant's share of Zonal Capacity Obligation for each day of the month and each Capacity Zone shall equal the product of: (i) the Capacity Zone's Zonal Capacity Obligation as calculated above and (ii) the ratio of the sum of the load serving entity's daily Coincident Peak Contributions, to the sum of all load serving entities' daily Coincident Peak Contributions in that Capacity Zone.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each day of the month and each Capacity Zone, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations. A Capacity Load Obligation can be a positive or negative value.

A Market Participant's share of Zonal Capacity Obligation will not be reconstituted to include the demand reduction of a Demand Capacity Resource, Demand Response Resource, or a Demand Response Distributed Energy Resource Aggregation.

III.13.7.5.2.1. Charges Associated with Dispatchable Asset Related Demands.

Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.5.3. Excess Revenues.

(a) For Capacity Commitment Periods beginning prior to June 1, 2022, revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.5.3.

(b) Any payment associated with a Capacity Supply Obligation Bilateral that was to accrue to a Capacity Acquiring Resource for a Capacity Supply Obligation that is terminated pursuant to Section

III.13.3.4A shall instead be allocated to Market Participants based on their pro rata share of all Capacity Load Obligations in the Capacity Zone in which the terminated resource is located.

III.13.7.5.4. Capacity Transfer Rights.

III.13.7.5.4.1. Definition and Payments to Holders of Capacity Transfer Rights.
This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

Capacity Transfer Rights are calculated for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone's Net Regional Clearing Price and absolute value of each Capacity Zone's Capacity Load Obligations, as calculated in Section III.13.7.5.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total

Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources.

III.13.7.5.4.2. Allocation of Capacity Transfer Rights.

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.5.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Connecticut Import Interface**. The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) **NEMA/Boston Import Interface**. Except as provided in Section III.13.7.5.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

III.13.7.5.4.3. Allocations of CTRs Resulting From Revised Capacity Zones.

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.5.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.5.4.4. Specifically Allocated CTRs Associated with Transmission Upgrades.

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(e) **Maine Export Interface**. Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine export interface for as long as Casco Bay continues to pay to support the transmission upgrades.

(f) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. This value will be divided by the number of days in the month to derive a daily settlement value.

III.13.7.5.4.5. Specifically Allocated CTRs for Pool-Planned Units.

(a) In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive for each Capacity Commitment Period an allocation of CTRs for each such unit that is the product of: (i) the MW quantity of capacity that the unit cleared in the Forward Capacity Auction associated with the Capacity Commitment Period; and (ii) the municipal utility's ownership entitlements in such unit. The CTRs allocated pursuant to this Section may be designated as self-supply quantities as described in Section III.13.1.6. Municipal utility ownership entitlements are set as shown in the table below and are not transferrable.

	Millstone 3	Seabrook	Stonybrook GT 1A	Stonybrook GT 1B	Stonybrook GT 1C	Stonybrook 2A	Stonybrook 2B	Wyman 4		
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%		
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%		
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%		
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%		
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%		
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%		
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%		
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%		
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%		
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%		
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%		
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%		
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%		
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%		
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%		
Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%		
Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%		
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%		
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%		

Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%		
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%		
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%		
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%		
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%		
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%		
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%		
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%		
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%		
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%		
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%		
Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%		

Allocation of CTRs as described in this Section shall expire on December 31, 2040. If a unit listed in the table above retires prior to December 31, 2040, however, allocation of CTRs for such unit shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant ("WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

(b) For any CTRs specifically allocated pursuant to this Section that are not designated self-supply quantities for the Capacity Commitment Period, the municipal utility entitlement holder shall receive a credit reflecting the value of such remaining CTRs. The value of each remaining CTR shall be calculated as the product of: (i) the Capacity Clearing Price for the Capacity Zone where the load of the municipal utility entitlement holder is located minus the Capacity Clearing Price for the Capacity Zone in which the Pool-Planned Unit is located; and (ii) the remaining MW quantity. This value will be divided by the number of days in the month to derive a daily settlement value.

III.13.7.5.5. Forward Capacity Market Net Charge Amount.

The Forward Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charges; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund (for Capacity Commitment Periods beginning prior to June 1, 2022); and (d) any applicable export charges.

III.15. Annual Capacity Market.

(a) Annual Capacity Market Overview.

The ISO shall administer an annual market for capacity (Annual Capacity Market) in accordance with the provisions of this Section III.15. For each one-year period from June 1 through May 31, starting with the period June 1, 2028 to May 31, 2029, for which Capacity Supply Obligations are assumed and payments are made in the Annual Capacity Market ("Capacity Commitment Period"), the ISO shall conduct an Annual Capacity Auction in accordance with the provisions of Section III.15.4 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Annual Capacity Auction, a resource must have Qualified Capacity resulting from the Annual Capacity Auction qualification process in accordance with the provisions of Sections III.15.2 and III.15.3. Obligations associated with the Annual Capacity Market may be traded during ISO-administered Monthly Reconfiguration Auctions and monthly bilateral transactions, in accordance with Section III.15.5 and Section III.15.6, respectively. The obligations of resources with Capacity Supply Obligations resulting from the Annual Capacity Auction, Monthly Reconfiguration Auctions, and monthly bilateral transactions are set forth in Section III.15.7. Payments and charges resulting from participation in the Annual Capacity Market, Monthly Reconfiguration Auctions, and bilateral transactions, as well as Capacity Performance Payments and System-Backed Export Charges, are set forth in Section III.15.8. The publication of auction-related information is set forth in Section III.15.9.

(b) Capacity Auction Calendar.

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2028, and for each Capacity Commitment Period thereafter, the ISO shall publish a calendar of dates and deadlines for the administration of the Capacity Market, with the dates and deadlines being consistent for each Annual Capacity Auction cycle. The Capacity Auction Calendar shall include specific dates and deadlines for all such Capacity Market dates and deadlines defined in this Section III.15 and related Tariff provisions. The following defines several milestone dates and deadlines.

(1) the Qualification Data Submission Deadline for the Annual Capacity Auction shall occur during the month of February;

(2) the Capacity Demonstration Deadline for the Annual Capacity Auction shall occur during the month of April; and

(3) the Annual Capacity Auction shall occur during the month of May.

(c) Modification of Capacity Auction Calendar.

The ISO may, on a prospective basis, reasonably revise any date or deadline in the Capacity Auction Calendar with written notice of such revision to each Governance Participant in the manner specified in Section 17.11(b) of the Participants Agreement prior to the occurrence of the date or deadline being revised. In the event a Market Participant fails to meet a deadline in the Capacity Auction Calendar for submission of information or data, the ISO shall extend such deadline for that Market Participant upon receipt of an order from the Commission granting the Market Participant's request for a waiver of such deadline for good cause shown. In no event shall a date or deadline be extended, prospectively by the ISO or retroactively by filing of a Market Participant, should doing so interfere with the ISO's effective administration of the Capacity Market.

(d) Effectiveness for the 2028-2029 Capacity Commitment Period and Thereafter.

The provisions of this Section III.15 are effective for the Capacity Commitment Period that runs from June 1, 2028 through May 31, 2029 and all Capacity Commitment Periods thereafter. Unless otherwise expressly stated, the provisions of this Section III.15 are not applicable to the Forward Capacity Market. Section III.13, addressing the administration of the Forward Capacity Market, shall continue to be effective for Capacity Commitment Periods through May 31, 2028. Unless otherwise expressly stated, the provisions of Section III.13 are not applicable to the Annual Capacity Market, Monthly Reconfiguration Auctions and monthly bilateral transactions addressed in this Section III.15 of Market Rule 1.

III.15.A. Non-Commercial Capacity Transition Rules.

All Capacity Resources that are on critical path schedule monitoring pursuant to Section III.13.3 as of June 1, 2028 are subject to the provisions of this Section III.15.A.

The ISO shall monitor the Non-Commercial Capacity resource's compliance with its critical path schedule from the time the ISO approves the request until the resource achieves FCM Commercial Operation, is terminated pursuant to Section III.15.A.2.1, or withdraws from critical path schedule monitoring pursuant to Section III.15.A.2.3.

III.15.A.1. Non-Commercial Capacity Resource Critical Path Schedule Reports.

For each resource that is being monitored for compliance with its critical path schedule, the Lead Market Participant for that resource must provide a written critical path schedule report to the ISO no later than five Business Days after the end of each calendar quarter. If the Lead Market Participant does not provide a written critical path schedule report to the ISO by the fifth Business Day after the end of the calendar quarter, then the ISO shall issue a notice thereof to the Lead Market Participant. If the Lead Market Participant fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.15.A.2.1. Each critical path schedule report shall include a complete updated version of the critical path schedule as described in Section III.15.A.1.1 through Section III.15.A.1.3.

III.15.A.1.1. Updated Critical Path Schedule.

The critical path schedule report must include a complete updated version of the critical path schedule as described in Section III.15.A.1, dated contemporaneously with the submission of the critical path schedule report. The updated critical path schedule must clearly indicate if the Lead Market Participant is proposing to change any of the milestones or dates from the previously submitted version of the critical path schedule, and must include an explanation of any such proposed changes. In the critical path schedule report, the Lead Market Participant must also explain in detail any proposed changes to the project design and the potential impact of such changes on the amount of capacity the resource will be able to provide.

III.15.A.1.2. Documentation of Milestones Achieved.

(a) For all new resources (except for Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW,

which are discussed in Section III.15.A.1.2(b)), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Lead Market Participant must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Major Permits**. For each major permit described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the permit was applied for and obtained as described in the critical path schedule. For permit applications, this documentation could include a dated copy of the permit application or cover letter requesting the permit. For approved permits, this documentation could include a dated copy of the approved permit or letter granting the permit from the permitting authority.

(ii) **Project Financing Closing**. The Lead Market Participant shall provide documentation showing that the sources of financing identified in the critical path schedule have committed to provide the amount of financing described in the critical path schedule. This documentation could include copies of commitment letters from the sources of financing.

(iii) **Major Equipment Orders**. For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the equipment was ordered as described in the critical path schedule. This documentation should include a copy of a dated confirmation of the order from the manufacturer or supplier. This documentation should confirm scheduled delivery dates consistent with milestone Section III.15.A.1.2(a)(v).

(iv) **Substantial Site Construction.** The Lead Market Participant shall provide documentation showing that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs.

(v) **Major Equipment Delivery**. For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the equipment was delivered to the project site and received as preliminarily acceptable as described in the critical path schedule. This documentation should include a copy of a dated confirmation of delivery to the project site.

(vi) **Major Equipment Testing.** For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the component was tested, including major systems testing as appropriate for the specific technology as described in the critical path schedule, and that the test results demonstrate the equipment's suitability to allow, in conjunction with other major components, subsequent operation of the project in accordance with the amount of capacity subject to critical path schedule monitoring in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning**. The Lead Market Participant shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity subject to critical path schedule monitoring. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Lead Market Participant is not required to provide documentation of Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) to the ISO as part of the ISO's critical path schedule monitoring. The ISO shall confirm that the resource has achieved Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) as described in the critical path schedule through the resource's compliance with the other relevant requirements of the Transmission, Markets and Services Tariff and the ISO New England System Rules.

(ix) **Transmission Upgrades**. The Lead Market Participant shall provide documentation showing that all interconnection facilities and upgrades identified for the project associated with the resource in a Transitional Cluster Study, Cluster Study, or Cluster Restudy (conducted pursuant to Section 7.5 of Schedule 22, Section 7.5 of Schedule 23, or Section 7.5 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff), or interconnection request or agreement under applicable state tariff, rules or procedures, have been completed.

(b) For Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Lead Market

Participant must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Substantial Project Completion**. The Lead Market Participant shall provide documentation showing the resource will be capable of providing its total offered demand reduction value as described in the New Demand Capacity Resource Qualification Package by the proposed Commercial Operation Date reported in the critical path schedule report.

(ii) **Additional Requirements**. For each customer and each prospective customer the Lead Market Participant shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's Asset has been registered with the ISO, then the Lead Market Participant shall also provide the Asset identification number.

III.15.A.1.3. Additional Relevant Information.

The Lead Market Participant must include in the critical path schedule report any other information regarding the status or progress of the project or any of the project milestones that might be relevant to the ISO's evaluation of the feasibility of the project being built in accordance with the critical path schedule.

III.15.A.2. Failure to Meet Critical Path Schedule.

If the ISO determines that any critical path schedule milestone date has been missed, or if the Lead Market Participant proposes a change to any milestone date in a quarterly critical path schedule report (as described in Section III.15.A.1), then the ISO shall consult with the Lead Market Participant to determine the impact of the missed milestone or proposed revision, and shall determine a revised date for the milestone and for any other milestones affected by the change. If a milestone date is revised for any reason, the ISO may require the Lead Market Participant to submit a written report to the ISO on the fifth Business Day of each month until the revised milestone is achieved detailing the progress toward meeting the revised milestone. If the Lead Market Participant does not provide a written critical path schedule report to the ISO on the fifth Business Day of a month, then the ISO shall issue a notice thereof to the Lead Market Participant. If the Lead Market Participant fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.15.A.2.1. Such a monthly reporting requirement, if imposed, shall be in addition to the quarterly critical path schedule reports described in Section III.15.A.1.

III.15.A.2.1. Termination of Critical Path Schedule Monitoring.

If a Lead Market Participant fails to comply with the requirements of Sections III.15.A.1 or III.15.A.2, or if, as a result of milestone date revisions, the date by which a resource will have achieved all its critical path schedule milestones is more than two years after the beginning of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation, then the ISO, after consultation with the Lead Market Participant, shall have the right, through a filing with the Commission, to terminate the resource's status on critical path schedule monitoring, provided that, where a Lead Market Participant voluntarily withdraws its resource from critical path schedule monitoring in accordance with Section III.15.A.2.3 no filing with the Commission shall be necessary. Upon Commission ruling, the Lead Market Participant shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation. If in these circumstances, however, the ISO does not take steps to terminate the resource and instead permits the Lead Market Participant to continue on critical path schedule monitoring, such continuation shall be subject to the ISO's right to revoke that permission and to file with the Commission to terminate the resource, and subject to continued reporting by the Lead Market Participant in accordance with Section III.15.A.1.

III.15.A.2.2. Termination of Interconnection Agreement.

If the ISO terminates, or files with the Commission to terminate, a resource's ability to remain on critical path schedule monitoring, the ISO shall have the right to terminate the Interconnection Agreement with that resource through a filing with the Commission and upon Commission ruling. The ISO shall also reduce the resource's assigned capacity interconnection service (or equivalent for resources not subject to the ISO Interconnection Procedures).

III.15.A.2.3. Withdrawal from Critical Path Schedule Monitoring.

A Lead Market Participant may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO.

III.15.A.3. Financial Assurance.

The financial assurance requirements for Designated FCM Participants offering Non-Commercial Capacity into the Forward Capacity Auction, as described in Section VII.B.2.b the ISO New England Financial Assurance Policy, shall continue to apply to all Capacity Resources that are subject to the provisions of this Section III.15.A.

Once a resource with Non-Commercial Capacity achieves commercial operation, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as a resource that has achieved Capacity Market Commercial Operation, as governed by the ISO New England Financial Assurance Policy.

If a Capacity Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited. Any financial assurance that is forfeited pursuant to Section III.15.A shall be used to reduce charges incurred by load in the relevant Capacity Zone.

III.15.A.4. Demonstrating FCM Commercial Operation

All Capacity Resources subject to the provisions of this Section III.15.A shall achieve commercial operation, for purposes of ending critical path schedule monitoring, in accordance with the FCM Commercial Operation requirements specified in Section III.13.3.8.

III.15.A.5. Settlement of Qualification Process Cost Reimbursement Deposit.

Upon the date on which the entire resource is no longer on critical path schedule monitoring, the ISO shall provide the Lead Market Participant with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff. All Capacity Resources that are subject to the provisions of this Section III.15.A shall be subject to the Forward Capacity Market payment and refund requirements as set forth in Section III.13.1.9.3.2 of the Tariff.

III.15.1. Auction Demand Curves and Other Auction Inputs.

III.15.1.1. Annual Capacity Auction Demand Curves.

The total amount of capacity cleared in the Annual Capacity Auction pursuant to Section III.15.4 shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the Capacity Zones modeled for the Annual Capacity Auction.

III.15.1.1.1. System-Wide Capacity Demand Curve.

The System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.15.1.1.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Capacity Auction Offer Price Cap.

III.15.1.1.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.15.1.1.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Capacity Auction Offer Price Cap.

III.15.1.1.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.15.1.1.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.15.1.1.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.15.1.2. Capacity Auction Offer Price Cap and the Cost of New Entry.

III.15.1.2.1. Calculation of Capacity Auction Offer Price Cap, CONE, and Net CONE.

(a) The Capacity Auction Offer Price Cap shall be the greater of (i) 1.6 multiplied by Net CONE; and (ii) CONE. References in this Section III.15 and Sections III.A.21 and III.A.24 to the Capacity Auction Offer Price Cap shall mean the Capacity Auction Offer Price Cap for the Annual Capacity Auction associated with the relevant Capacity Commitment Period.

(b) To determine the CONE and Net CONE for the Annual Capacity Auctions associated with the Capacity Commitment Period beginning on June 1, 2028 and the Capacity Commitment Period beginning on June 1, 2029, the ISO shall make interim-year adjustments as described in Section III.15.1.2.2 to the following CONE and Net CONE calculated for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025:

(i) CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 was $12.400/kW-month.

(ii) Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 was $7.468/kW-month.

(c) The ISO shall recalculate CONE and Net CONE for the Annual Capacity Auction for the Capacity Commitment Period beginning on June 1, 2030. Thereafter, CONE and Net CONE shall be recalculated no less often than once every four years. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders, and the new values will be filed with the Commission prior to the Annual Capacity Auction in which the new value is to apply.

III.15.1.2.2. Interim-Year Adjustments to CONE and Net CONE.

(a) For years in which no full recalculation is performed pursuant to Section III.15.1.2.1, CONE and Net CONE shall be adjusted for each Annual Capacity Auction with the following updates to the capital

budgeting model used to calculate the CONE and Net CONE values set forth above in this Section III.15.1.2:

(1) Each line item associated with capital costs that is included in the capital budgeting model shall be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114).

(2) For each line item in (1) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the CONE and Net CONE values set forth in Section III.15.1.2.1. The value of each line item associated with capital costs in the capital budgeting model will be adjusted by the relevant multiplier.

(3) The energy and ancillary services offset values in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE, for each month of the Capacity Commitment Period to which the updated value will apply.

(4) The annual adjustment to CONE and Net CONE for the Annual Capacity Auction for the Capacity Commitment Period beginning June 1, 2028, shall use a cost of debt of 6.85% and a cost of equity of 13.80%. These values shall also be used for the Annual Capacity Auction for the Capacity Commitment Period beginning on June 1, 2029.

(5) If any of the values required for the calculations described in this Section III.15.1.2.2 are unavailable, then comparable values, prices or sources shall be used.

(b) The CONE and Net CONE values adjusted pursuant to this Section III.15.1.2.2 will be published on the ISO's website.

III.15.2. Capacity Resource Qualification.

Each resource, or portion thereof, must qualify as a Generating Capacity Resource, an Import Capacity Resource, a Demand Capacity Resource, or a Distributed Energy Capacity Resource. Each resource must be at least 100 kW in size to participate in an Annual Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of Section III.13 became effective. The summer period of a Capacity Resource's Seasonal Qualified Capacity Values shall be the months of June through September and the winter period shall be the months of October through May, except in the case of Demand Capacity Resources, where the summer period shall be the months of April through November and the winter period shall be the months of December through March.

This Section III.15.2 details the requirements of the qualification process for the Annual Capacity Auction, as well as certain requirements related to Monthly Reconfiguration Auctions and Capacity Supply Obligation Bilateral transactions. Data submission and demonstration requirements for resources that have never previously counted as capacity and seek to qualify to participate in an Annual Capacity Auction, are set forth in Section III.15.2.1. Data submission and demonstration requirements for resources that have never previously counted as capacity and seek to qualify to participate in a Monthly Reconfiguration Auction are set forth in Section III.15.2.2. Qualification requirements with respect to interconnection service are addressed in Section III.15.2.3. Qualification requirements with respect to resources that have previously counted as capacity and have materially changed are addressed in Section III.15.2.4. Following the Annual Capacity Auction's Qualification Data Submission Deadline, the ISO calculates and provides to Lead Market Participants Advisory Qualified Capacity Values for each Capacity Resource, per Section III.15.2.5. Lead Market Participants then have until the Capacity Demonstration Deadline to demonstrate that their Capacity Resources have achieved Commercial Operation, per Section III.15.2.6. Thereafter, the ISO calculates Seasonal Qualified Capacity Values for each Capacity Resource, per Section III.15.2.7, which values are subject to the challenge process addressed therein. Lead Market Participants are then permitted to submit Composite Offers in accordance with Section III.15.2.8, and load serving entities are permitted to submit self-supply designations in accordance with III.15.2.9. Final Qualified Capacity values for each Capacity Resource are calculated by the ISO one Business Day prior to the opening of the Annual Capacity Auction Offer Window in accordance with Section III.15.2.10. The publication of offer information during the qualification process and after the Annual Capacity Auction is addressed in Section III.15.2.11.

Resources seeking to qualify for an Annual Capacity Auction may be subject to buyer-side market power review and mitigation pursuant to Section III.A.21 and must abide by the applicable submission

requirements and timelines set forth therein prior to seeking to qualify for an Annual Capacity Auction. To the extent not already established for the purposes of the submission requirements of Section III.A.21.1.5, all capacity suppliers seeking to qualify for an Annual Capacity Auction must be Market Participants prior to the Qualification Data Submission Deadline. The Lead Market Participant for a resource participating in an Annual Capacity Auction may not change during the period beginning 15 Business Days prior to the opening of the Annual Capacity Auction Offer Window and ending with the posting of the results of the Annual Capacity Auction.

III.15.2.1. Qualification Data Submission Requirements.

III.15.2.1.1. Qualification Data Submission Package.

(a) For a resource that has not previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction to qualify as a Capacity Resource for participation in an Annual Capacity Auction, a Lead Market Participant must submit the following information to the ISO by the Qualification Data Submission Deadline, as applicable:

(i) the resource name;

(ii) the Lead Market Participant's contact information;

(iii) the date by which the resource is expected to complete its capacity demonstration pursuant to III.15.2.6(c) or to update its as-built data pursuant to III.15.2.6(d);

(iv) the resource address or location, and if available, asset identification number;

(v) whether the resource has ever previously had a Capacity Supply Obligation;

(vi) the location of the resource's interconnection;

(vii) the estimated Seasonal Qualified Capacity Values of the resource, as well as an estimate of any incremental Seasonal Qualified Capacity Values (in MW) (for Generating Capacity Resources and Import Capacity Resources);

(viii) the estimated total summer and winter demand reduction value (for Demand Capacity Resources and Distributed Energy Capacity Resources) or net injection capability values per facility (for Distributed Energy Capacity Resources);

(ix) a description of the resource, including (for Generating Capacity Resources and Import Capacity Resources) a general description of the resource's equipment configuration and a description of the resource technology type, and (for Demand Capacity Resources) a description of the resource's Demand Capacity Resource type and measure type, and (for Distributed Energy Capacity Resources) a description of the project and its configuration, including the types of generation and demand response composing the project, and (for

Generating Capacity Resources and Distributed Energy Capacity Resources comprising generation) a one-line diagram of the resource's configuration;

(x) for resources supported by an Internal Elective Transmission Upgrade, all unique project identifiers associated with the Internal Elective Transmission Upgrade;

(xi) for Generating Capacity Resources with a contract to export capacity from the New England Control Area during the Capacity Commitment Period, the interface over which the capacity will be exported and the contract associated with the export capacity;

(xii) Additional requirements for Import Capacity Resources, the interface over which the capacity will be imported and one of the following submissions documenting the source of the imported capacity, as further detailed in Section III.15.2.1.1.1: (i) documentation of a contract entered into before the Qualification Data Submission Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for one or more years encompassing the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iii) documentation for system-backed import capacity that the Import Capacity Resource will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load.

(xiii) Additional requirements for Demand Capacity Resources, as further detailed in Section III.15.2.1.1.2: resource technical and credit/financial contacts; Measurement and Verification Plan (for On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources); Load Zone and Dispatch Zone (for Active Demand Capacity Resources);

(xiv) Additional requirements for Distributed Energy Capacity Resources, as further detailed in Section III.15.2.1.1.3: expected nameplate capacity by technology type per facility; installation date of facilities that are part of the project and already constructed, installed, or in commercial operation; indication of whether the project elects Intermittent Power Resource treatment; resource technical and credit/financial contacts; Load Zone, Dispatch Zone and DRR Aggregation Zone;

(xv) Additional requirements for resources with capacity impacted by ambient air conditions between 90 degrees and 100 degrees, as further detailed in Section III.15.2.1.5; and

(xvi) Additional requirements for resources seeking ISO-estimated Seasonal Qualified Capacity Values, as further detailed in III.15.2.6(d): the Qualification Data Submission Package shall satisfy the technical data requirements associated with such resources and be supplemented with the as-built status of the resource on the date of the relevant Capacity Demonstration Deadline.

(b) By submitting the required qualification information, the Lead Market Participant certifies that a Capacity Offer from the resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 of Section II of the Tariff.

(c) The ISO may waive the submission of any information not required for evaluation of the resource.

III.15.2.1.1.1. Additional Import Capacity Resource Requirements.

Import Capacity Resources must be backed by one or more External Resources or by an external Control Area for the duration of the relevant Capacity Commitment Period. An external demand resource may not be an Import Capacity Resource. External nodes shall be established and mapped to Capacity Zones pursuant to the provisions in Attachment K to Section II of the Transmission, Markets and Services Tariff. For the purposes of the qualification process, all Import Capacity Resources shall be treated as if they had never previously participated as capacity and must submit the materials described pursuant to this Section III.15.2.1.1 for each Capacity Commitment Period for which the Import Capacity Resource seeks to qualify capacity. Import Capacity Resources backed by an External Control Area that does not have a Coordination Agreement with the ISO shall be ineligible to participate in the Annual Capacity Market. No single Import Capacity Resource may qualify capacity in excess of the external interface limits as described in Section III.12.10.

An Elective Transmission Upgrade with Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall have its external node modeled in the Annual Capacity Auction after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the Annual Capacity Auction qualification requirements of this Section III.15.2.1 and demonstration requirements of III.15.2.6. The Qualified Capacity of all Import Capacity Resources associated with an Elective Transmission Upgrade shall not exceed the Elective Transmission Upgrade's Capacity Network Import Capability.

Capacity Offers for Import Capacity Resources shall be subject to rationing except for Capacity Offers priced above the Capacity Offer Price Threshold for Import Capacity resources associated with an Elective Transmission Upgrade, which must obtain a Capacity Supply Obligation or not in whole unless the Capacity Offer indicated that it may be rationed as described in III.15.4.1.

III.15.2.1.1.1.1. Imports Backed by External Resources.

If the Import Capacity Resource will be backed by one or more External Resources, the Lead Market Participant shall submit a description of how the Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify. The description must indicate specifically which External Resources will back the Import Capacity Resource during the Capacity Commitment Period and contain the relevant historical performance data for each resource. If those External Resources are not owned or controlled directly by the Lead Market Participant, the description must include a commitment that the External Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.15.2.1.1.1.2. Imports Backed by an External Control Area.

If the Import Capacity Resource will be backed by an external Control Area, the Lead Market Participant shall submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the Import Capacity Resource.

III.15.2.1.1.1.3. Imports Crossing Intervening Control Areas.

Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) for imports crossing a single intervening Control Area, the Lead Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the Qualification Data Submission Deadline, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing; (2) for imports crossing more than one intervening Control Area, in addition to the requirements above, the Lead Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals,

by the Qualification Data Submission Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load; and (3) the Lead Market Participant entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.15.2.1.1.2. Additional Demand Capacity Resource Requirements.

A Demand Capacity Resource may be an Active Demand Capacity Resource, On-Peak Demand Capacity Resource, or Seasonal Peak Demand Capacity Resource, and may include an end-use customer facility with a Net Supply Capability of 5 MW or more only if the facility's Net Supply Capability does not exceed its Maximum Facility Load. Demand Capacity Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Capacity Resource. Demand Capacity Resources are not permitted to submit a Capacity Offer to import into or export out of the New England Control Area.

For a resource, or portion thereof, that never previously obtained a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction to qualify as an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource for the Capacity Commitment Period beginning June 1, 2028, the measure or measures contained in the resource must not have been in-service prior to June 1, 2024. For a resource, or portion thereof, that never previously obtained a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction to qualify as an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource in the Annual Capacity Auction or Monthly Reconfiguration Auction, as relevant, for or during the Capacity Commitment Period beginning June 1, 2029, and all Capacity Commitment Periods thereafter, the measure or measures contained in the resource must have been placed in-service or previously qualified as capacity no more than six months before the prior Annual Capacity Auction's Capacity Demonstration Deadline.

III.15.2.1.1.2.1. Measurement and Verification of Demand Capacity Resources.

(a) To demonstrate the demand reduction value of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, the Lead Market Participant of such a resource participating in the Annual Capacity Auction, Capacity Supply Obligation Bilaterals, or Monthly Reconfiguration Auctions shall submit to the ISO Measurement and Verification Documents in accordance with this Section III.15.2.1.1.2.1 and the ISO New England Manuals. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.15.2.1.1.2.1 and the ISO New England Manuals.

(b) Measurement and Verification Documents must demonstrate both availability and performance of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource in reducing demand coincident with Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours such that the reported monthly demand reduction value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manuals and ISO New England Operating Procedures. The Measurement and Verification Documents shall: (1) serve as the basis for the claimed demand reduction value of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource; (2) document the measurement and verification performed to verify the achieved demand reduction value of the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource; and (3) contain a projection of the On-Peak Demand Capacity Resource's or Seasonal Peak Demand Capacity Resource's demand reduction value for each month of the Capacity Commitment Period and, for those Demand Capacity Resources composed of energy efficiency measures, over the expected Measure Lives. An On-Peak Demand Capacity Resource's or Seasonal Peak Demand Capacity Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours. If an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource includes Distributed Generation, the Measurement and Verification Documents must describe the individual metering or metering protocol used to monitor and verify the output of the Distributed Generation, consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals.

(c) The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Annual Capacity Auction qualification process, as described in this Section III.15.2.1.1.2.1, and monthly Measurement and Verification data submitted during the Capacity Commitment Period. The monthly Measurement and Verification data shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan.

Such monthly Measurement and Verification data shall document the Lead Market Participant's total demand reduction value from both eligible pre-existing measures and new measures, and the Lead Market Participant's total demand reduction value from both eligible pre-existing measures and new measures, for all measures in operation as of the end of the previous month. The monthly Measurement and Verification data shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Lead Market Participants. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

(d) Lead Market Participants for On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources shall submit no less frequently than once per year, a statement certifying that the Demand Capacity Resource for which the Lead Market Participant is requesting compensation continues to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than ten Business Days before the Qualification Data Submission Deadline.

(e) For On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources comprising customer facilities with greater than or equal to 10 kW of demand reduction value per facility, Lead Market Participants shall maintain records of retail customers served, including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly demand reduction values. For On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources targeting customer facilities with under 10 kW of demand reduction value per facility, the Lead Market Participant shall maintain records as described above for customer facilities with greater than or equal to 10 kW of demand reduction value per facility, or shall maintain records of aggregated demand reduction values and measures installed by Load Zone and meter domain. Lead Market Participants shall maintain such records until the end of the Measure Life, or until the Demand Capacity Resource is retired or deactivated from the Annual Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

(f) The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Annual Capacity Auction qualification

process as described in Section III.15.2 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Lead Market Participant to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.15.2.1.1.3. Additional Distributed Energy Capacity Resource Requirements.

(a) Distributed Energy Capacity Resources. A facility connected at a point of interconnection that is 5 MW or greater cannot be a part of a Distributed Energy Capacity Resource. A Distributed Energy Capacity Resource comprises one or more Distributed Energy Resource Aggregations located in a single Capacity Zone and a single DRR Aggregation Zone, except that (a) a Settlement Only Distributed Energy Resource Aggregation may not participate in a Distributed Energy Capacity Resource with any other type of Distributed Energy Resource Aggregation, and (b) an end-use customer facility participating as part of an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource with measures other than Energy Efficiency may not participate in a Distributed Energy Capacity Resource. Distributed Energy Capacity Resources are not permitted to submit a Capacity Offer to import into or export out of the New England Control Area. For purposes of this Section III.15.2.1.1.3: (i) if a facility is expected to interconnect at a point of interconnection, its net injection capability is the generation capability of the installed generation technology at the point of interconnection; (ii) if a facility is expected to interconnect at a Retail Delivery Point and does not plan to participate in the aggregation as a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation, the net injection capability is the lesser of the generation less the load profile measured at the location of the end-use customer meter or the amount the facility is contractually able to inject.

(b) Demand Response Resource in Distributed Energy Capacity Resources. If the Distributed Energy Capacity Resource includes Demand Response Resources, the completed Qualification Data Submission Package shall include the following additional information: the estimated summer and winter demand reduction values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses); the estimated total summer and winter demand reduction value of the Demand Response Resource (which must be consistent with the baseline calculation methodology in Section

III.8.2); and supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated demand reduction values.

(c) Net Injection of 5 MW or Greater. If the Distributed Energy Capacity Resource contains a Distributed Energy Resource Aggregation with a facility with net injection of 5 MW or greater at a Retail Delivery Point, then the completed Qualification Data Submission Package for such a resource shall include the following additional information: the Pnode and service address at which the end-use facility is located; nameplate MW and net injection capability; non-coincident peak load (MW) of the facility without generation; technology type; and the Market Participant's portion of generation requested to be included as Qualified Capacity.

(d) Net Injection Greater Than or Equal to 1 MW and less than 5 MW. If the Distributed Energy Capacity Resource contains a Distributed Energy Resource Aggregation with a facility that has net injection capability at the point of interconnection of 1 MW or greater and less than 5 MW, then the completed Qualification Data Submission Package for such a facility shall include the following additional information: distribution bus; technology type; nameplate MW; one-line diagram of the plant and station facilities, including any known transmission facilities; if the facility is intermittent, the requested contribution of Qualified Capacity and supporting site-specific data; if an interconnection agreement is required under state requirements, the date when the interconnection request was submitted and the status of that interconnection request.

III.15.2.1.2. Market Power Review.

Lead Market Participants seeking to qualify a Capacity Resource that has not previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or that is otherwise treated as if it had never done so pursuant to this Section III.15.2, must comply with the market power review provisions of Section III.A.21 by the Annual Capacity Auction Qualification Data Submission Deadline.

III.15.2.1.3. Capacity Commitment Period Election.

For the Annual Capacity Auctions for the 2028-2029, 2029-2030 and 2030-2031 Capacity Commitment Periods, a Lead Market Participant that has made the election in Section III.13.1.1.2.2.4 of the Forward Capacity Market rules with respect to a Capacity Resource must specify by the Qualification Data Submission Deadline whether it elects to continue to have the associated Capacity Supply Obligation and Capacity Clearing Price apply in Annual Capacity Auctions for the balance of the period permitted for

such Capacity Resource pursuant to Section III.13.1.1.2.2.4. Should a Lead Market Participant elect to terminate Section III.13.1.1.2.2.4 treatment for its Capacity Resource, it may not re-elect such treatment for any future Annual Capacity Auctions.

A Lead Market Participant that has made the election in Section III.13.1.1.2.2.4 of the Forward Capacity Market rules with respect to a Capacity Resource which has not achieved Capacity Market Commercial Operation as defined in Section III.15.2.6 of Market Rule 1 may not participate in the Annual Capacity Auction for the 2028-2029 Capacity Commitment Period and shall not have the previously elected Capacity Supply Obligation and Capacity Clearing Price apply for the 2028-2029 Capacity Commitment Period. Should such resource achieve Capacity Market Commercial Operation in time for participation in the Annual Capacity Auction for the 2029-2030 Capacity Commitment Period, or the Annual Capacity Auction for the 2030-2031 Capacity Commitment Period, it may elect to have the Capacity Supply Obligation and Capacity Clearing Price it received pursuant to Section III.13.1.1.2.2.4 apply for the balance of the period permitted for such Capacity Resource pursuant to Section III.13.1.1.2.2.4, and in no event after the Annual Capacity Auction for the 2030-2031 Capacity Commitment Period.

III.15.2.1.4. Material Deficiency in Data Submission.

In its review of a Lead Market Participant's data submission under this Section III.15.2.1, the ISO may consult with the Lead Market Participant, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO determines that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Lead Market Participant may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

In the event the ISO determines that a Lead Market Participant's data submission under Section III.15.2.1 is materially deficient, it shall notify the participant of such deficiencies at least ten Business Days prior to publication of the Advisory Seasonal Qualified Capacity Values, and the Lead Market Participant shall have five Business Days from the date of notification to cure the deficiencies. Should a Lead Market Participant fail to cure such deficiencies by the end of the cure period, it shall not be permitted to participate in the Annual Capacity Auction. In the event of such a rejection, the ISO shall provide the

Lead Market Participant with a written explanation of the reason for the rejection within ten Business Days of the close of the cure period.

III.15.2.1.5. Additional Qualification Requirements for Ambient Air Condition Impacts.

In the Qualification Data Submission Package, a Lead Market Participant may submit documentation indicating that a portion of its resource's capacity will not be physically available due to an ambient air condition. The size of such ambient air condition is calculated as the difference between the summer Qualified Capacity at 90 degrees and the rating of the resource at 100 degrees. The ISO shall verify during the qualification process the size of the ambient air condition.

III.15.2.2. Monthly Reconfiguration Auction Qualification.

For a resource that has not previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction to qualify as a Capacity Resource for the purpose of participation in a Monthly Reconfiguration Auction pursuant to Section III.15.5 or bilateral activities pursuant to Section III.15.6, prior to the Capacity Demonstration Deadline for the relevant month a Lead Market Participant must: (1) submit the Qualification Data Submission Package as described in Section III.15.2.1 (except for the information described at Section III.15.2.1.2) by the Capacity Demonstration Deadline for the relevant month, except that an Import Capacity Resource or a Resource seeking ISO-estimated Seasonal Qualified Capacity Values pursuant to Section III.15.2.6(d) must submit its Qualification Data Submission Package 30 calendar days prior to the Capacity Demonstration Deadline; and (2) complete a capacity demonstration pursuant to Section III.15.2.6.

III.15.2.3. Deliverability Review.

A Generating Capacity Resource, Active Demand Capacity Resource, Import Capacity Resource associated with an External Elective Transmission Upgrade, and Distributed Energy Capacity Resource must satisfy the deliverability review requirements described in this Section III.15.2.3 in order to qualify capacity for participation in an Annual Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction above the deliverability value associated with the resource's qualification for any previous Forward Capacity Auction, Annual Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction. None of the provisions of this Section III.15.2, supersedes, replaces, or satisfies any of the requirements of Schedules 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder.

III.15.2.3.1. Deliverability Review for Capacity Resources Associated with Generating Facilities or External Elective Transmission Upgrades Subject to Schedule 22, 23, or 25 of Section II of the Tariff.

A Generating Facility or External Elective Transmission Upgrade subject to Schedules 22, 23 or 25 of Section II of the Tariff must complete the applicable interconnection processes set forth therein and have been assigned, as applicable, either Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service, as necessary to support the delivery of the associated Capacity Resource's Qualified Capacity.

III.15.2.3.2. Deliverability Review for Capacity Resources Associated with Resources Not Subject to Schedule 22, 23, or 25 of Section II of the Tariff.

For a Generating Capacity Resource, Active Demand Capacity Resource, or Distributed Energy Capacity Resource not subject to Schedules 22, 23, or 25 of Section II of the Tariff, the ISO shall perform a deliverability review based on: (1) the information provided in the resource's Qualification Data Submission Package; and (2) the results of the ISO's most recent deliverability analysis, performed consistent with the criteria and conditions conducted as described in the ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that such a resource cannot deliver any of the requested incremental capacity, then the resource or incremental portion thereof shall not qualify for participation in the Capacity Market as reflected in the Seasonal Qualified Capacity Values issued pursuant to Section III.15.2.7; otherwise, the ISO shall determine that the requested Qualified Capacity of the Capacity Resource is deliverable, and the Capacity Resource shall be eligible to continue to proceed with the remainder of the processes described in this Section III.15.2.

III.15.2.4. Resources Previously Counted as Capacity.

Resources that have previously counted as capacity shall, for the purposes of Section III.15.2, be treated as if they had never previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction if: (1) there is a material change to the Capacity Resource as described in III.15.2.4.1, or (2) if a deactivated or retired resource seeks to re-enter the Capacity Market pursuant to III.15.2.4.2.

III.15.2.4.1. Material Change to a Capacity Resource.

(a) A Lead Market Participant that materially changes a Capacity Resource that has previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or plans to do so prior to the relevant Capacity Demonstration Deadline, may, by the relevant Qualification Data

Submission Deadline or monthly Capacity Demonstration Deadline, inform the ISO of that material change, update the information provided under Section III.15.2.1.1 to reflect the change to the Capacity Resource, and demonstrate its updated Commercial Capacity pursuant to Section III.15.2.6. The updated Qualified Capacity of the resource, accounting for the change, shall be calculated in accordance with Section III.15.3.1 for the subsequent Annual Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral. The Seasonal Qualified Capacity of a Capacity Resource that notifies the ISO of a material change but does not demonstrate pursuant to III.15.2.6 shall remain unmodified until demonstration of the material change occurs.

(b) For purposes of this Section III.15.2.4, a material change to a Capacity Resource is a change to the design or operating characteristics of the resource, including its interconnection facilities, that may have a significant effect on the reliability or operating characteristics associated with the Capacity Resource, and shall include, but not be limited to, changing the resource technology type, making a change to the Capacity Resource that increases or decreases the resource's Annual Qualified Capacity by greater than the lesser of 5 MW or 10 percent, or any change to the resource that requires a material modification to its interconnection agreement. No less than 30 calendar days prior to the Qualification Data Submission Deadline or Monthly Capacity Demonstration Deadline, as relevant, a Lead Market Participant may request, and the ISO shall within 20 calendar days provide, a determination regarding whether a change qualifies as a material change to a Capacity Resource pursuant to this Section III.15.2.4 and requires submission of the materials required pursuant to Section III.15.2.1.1.

III.15.2.4.2. Treatment of Previously Deactivated or Retired Resources.

In order to qualify for participation in the Capacity Market, a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) must: (1) have reached its deactivation date and reduced its Capacity Network Resource Capability pursuant to Section II.48.3; (2) if the resource was compensated for delaying deactivation through a Commission-approved cost-of-service agreement, have refunded to the ISO all costs subject to refund under the claw-back provision set forth in Section II.54.1; and (3) have satisfied the provisions of Section III.15.2, including submission of the Qualification Data Submission Package described in Section III.15.2.1 and completed the capacity interconnection service requirements described in Section III.15.2.3, as if the resource had never previously received a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction.

III.15.2.5. Calculation of Advisory Qualified Capacity Values.

Following the Qualification Data Submission Deadline, by a date in the month of February published on the Capacity Auction Calendar, the ISO shall calculate and provide to Lead Market Participants summer and winter Advisory Qualified Capacity Values for each resource that has met the data submission requirements in Section III.15.2.1. The Advisory Qualified Capacity Values of any resource that has not previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or is otherwise treated as if it had not done so, shall equal its demonstrated Commercial Capacity determined in accordance with Section III.15.2.6; except that in the event that a resource has not yet demonstrated a portion of its Commercial Capacity, its Advisory Qualified Capacity Values shall equal the sum of its Commercial Capacity and the estimated incremental Seasonal Qualified Capacity Values of the resource as submitted pursuant to Section III.15.2.1. For all other resources, the Advisory Qualified Capacity Values shall equal the Capacity Resource's summer and winter Qualified Capacity as calculated pursuant to Section III.15.3.

During the period beginning with the ISO's issuance of Advisory Qualified Capacity Values and ending with the conclusion of the Annual Capacity Auction, any change to a capacity resource or the information submitted in a Qualification Data Submission Package shall not impact the resource's Seasonal Qualified Capacity Values for that Annual Capacity Auction unless the change has already been accounted for in the submitted Qualification Data Submission Package, or is made pursuant to Section III.15.2.1.4 or Section III.15.2.7.

III.15.2.6. Capacity Commercial Operation Demonstration Requirement.

To participate in an Annual Capacity Auction, Monthly Reconfiguration Auctions, or a Capacity Supply Obligation Bilateral transaction, a Capacity Resource must first demonstrate that its capacity is commercially operational by meeting the demonstration requirements in this Section III.15.2.6 by the applicable Capacity Demonstration Deadline. A resource that meets the demonstration requirements of this Section III.15.2.6 shall be deemed to have achieved Capacity Market Commercial Operation.

(a) Demonstration must be completed (i) prior to a Capacity Resource's initial participation in the Annual Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction, and (ii) when a Capacity Resource that has previously received a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction materially changes or reactivates pursuant to Section III.15.2.4.

(b) The Capacity Demonstration Deadline for each Annual Capacity Auction shall be during the month of April preceding the relevant Annual Capacity Auction, as published on the Capacity Auction

Calendar; for each Monthly Reconfiguration Auction and Capacity Supply Obligation Bilateral window, the Capacity Demonstration Deadline shall precede the relevant Obligation Month by approximately two weeks, as published on the Capacity Auction Calendar.

(c) To demonstrate commercial capacity, a resource must perform an audit by the relevant Capacity Demonstration Deadline, using the following audit requirements:

(i) For Generating Capacity Resources that are not Intermittent Power Resources, each Generator Asset must perform an Establish Claim Capability Audit pursuant to Section III.1.5.1.2, provide the data described in ISO New England Operating Procedure No. 23, and have its audit value become effective pursuant to Section III.1.5.1.2(d)(iv).

(ii) For Generating Capacity Resources that are Intermittent Power Resources, each Generator Asset must perform a Seasonal Claim Capability Audit pursuant to Section III.1.5.1.3, provide the data described in ISO New England Operating Procedure No. 23, and have its audit value become effective pursuant to Section III.1.5.1.3(i).

(iii) For Active Demand Capacity Resources, each Demand Response Asset must perform a Seasonal DR Audit pursuant to III.1.5.1.3.1, as specified by season in III.15.7.1.5.3(c), requested by the Lead Market Participant, and have its audit value become effective pursuant to Section III.1.5.1.3.1(m).

(iv) For Demand Capacity Resources that are not Active Demand Capacity Resources, each Demand Capacity Resource must perform a Passive DR Audit pursuant to III.15.7.1.5.4, as specified by season in III.15.7.1.5.3(c), at the request of the Lead Market Participant, and have its audit value become effective pursuant to Section III.15.7.1.5.4(f).

(v) For Distributed Energy Capacity Resources, each asset comprising the Distributed Energy Capacity Resource must meet the demonstration requirement in sub-sections (i) through (iii) above for its corresponding asset type.

(vi) For Import Capacity Resources, demonstration is achieved through provision of performance data in the resource's Qualification Data Submission Package in accordance with Section III.15.2.1, except that Import Capacity Resources associated with an external Elective

Transmission Upgrade must demonstrate the ability to transfer power between regions pursuant to Schedule 25, Article 6.

(d) For those resources identified in Sections III.15.2.6(c)(ii), III.15.2.6(c)(iv), and III.15.2.6(c)(v) providing asset-level meter-based performance data by the Capacity Demonstration Deadline that is, as determined by the Lead Market Participant, of insufficient duration to establish accurate Seasonal Qualified Capacity Values, or for a period inconsistent with the audit described in Section III.15.2.6(c), the Lead Market Participant may request that the ISO determine Seasonal Qualified Capacity Values based on the lesser of: (1) the Seasonal Qualified Capacity Values requested for qualification by the Lead Market Participant; or (2) the Seasonal Qualified Capacity Values estimated by the ISO. In no instance shall the Seasonal Qualified Capacity Values developed pursuant to this Section III.15.2.6(d) exceed a resource's seasonal Capacity Network Resource Interconnection Service, or its equivalent.

The ISO-estimated Seasonal Qualified Capacity Values shall be based on technical data requirements for recently commercial resources identified in the Qualification Data Submission Package. The Qualification Data Submission Package of resources seeking ISO-estimated Seasonal Qualified Capacity Values shall include a description of the as-built status of the resource at time of submission, including whether the resource is fully or partially operational. For those resources seeking ISO-estimated Seasonal Qualified Capacity Values, the Qualification Data Submission Package must be submitted to the ISO by the Lead Market Participant by the Qualification Data Submission Deadline for the Annual Capacity Auction, or 30 days prior to the relevant monthly Capacity Demonstration Deadline, with the submission updated at the time of the Capacity Demonstration Deadline to reflect the as-built status of the resource. Resources satisfying the provisions of this Section III.15.2.6(d) shall be deemed to have demonstrated Commercial Capacity.

Resources seeking ISO-estimated Seasonal Qualified Capacity Values that have completed the relevant audit described in III.15.2.6(c) for only one season may elect to use the ISO-estimated Seasonal Qualified Capacity Values for one or both seasons. The ISO-estimated Seasonal Qualified Capacity Values may constitute a resource's Seasonal Qualified Capacity Value for up to one year after issuance, but shall be valid for no longer than one year after a resource becomes fully operational. A Lead Market Participant may request replacement of ISO-estimated Seasonal Qualified Capacity Values once the relevant seasonal audit has been completed.

III.15.2.7. Seasonal Qualified Capacity Values and Challenge Process.

(a) Following the April Capacity Demonstration Deadline, for each Capacity Resource qualified to participate in an Annual Capacity Auction, the ISO shall notify the Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity, calculated in accordance with Section III.15.3, and the Load Zone in which the resource is located. This notification will be provided by the Seasonal Qualified Capacity Notification Date specified in the Capacity Auction Calendar.

(b) If the Lead Market Participant believes that the ISO has made a mathematical error in calculating the summer Qualified Capacity or winter Qualified Capacity for a Capacity Resource, then the Lead Market Participant must notify the ISO within five calendar days of the Seasonal Qualified Capacity Notification Date.

(c) If a Capacity Resource's summer Qualified Capacity has been subject to a significant decrease pursuant to Section III.15.3.6, the Lead Market Participant may submit a restoration plan in accordance with Section III.15.3.6(b) within five calendar days of the Seasonal Qualified Capacity Notification Date.

(d) The ISO shall notify the Lead Market Participant of the outcome of any challenge submitted under (b) above or of its determination regarding the sufficiency of a restoration plan submitted under (c) above, by the date specified in the Capacity Auction Calendar for such responses. In assessing the sufficiency of a restoration plan, the ISO shall determine whether the plan provides sufficient information to support the reasonable likelihood of the resource providing capacity consistent with its summer Qualified Capacity value by the start of the Capacity Commitment Period.

III.15.2.8. Offers Composed of Separate Resources (Composite Offers).

Separate resources seeking to participate together in an Annual Capacity Auction shall submit a Composite Offer Form no later than the Composite Offer Deadline, which shall be approximately two business days prior to the auction as specified in the Capacity Auction Calendar, with the exception that Distributed Energy Capacity Resources may not participate in composite offers. Composite offers may not be modified or withdrawn after the Composite Offer Deadline. Composite offers must meet the following conditions:

(a) In all months of the summer period of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources combined meet the amount of the offer in all

months of the winter period; and (ii) to combine for a month, that month must be a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of a composite offer must qualify in accordance with all of the provisions of Section III.15.2 applicable to that resource type. A composite offer participates in the Annual Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period.

(c) The summer Qualified Capacity of a composite offer shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.15.3.7 shall apply, even where one or more of the resources that are part of the offer composed of separate resources is an Intermittent Power Resource. If the winter capacity of the composite offer in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

(d) Composite offers are subject to the locational restrictions specified in the following table:

		Location of Summer Resource			
		Import-Constrained Capacity Zone	Rest-of-Pool Capacity Zone	Export-Constrained Capacity Zone	Nested Export-Constrained Capacity Zone
Location of Winter Resource	Import-Constrained Capacity Zone	Eligible (within same Capacity Zone)	Eligible	Eligible	Eligible
	Rest-of-Pool Capacity Zone	Ineligible	Eligible	Eligible	Eligible
	Export-Constrained Capacity Zone	Ineligible	Ineligible	Eligible (within same Capacity Zone)	Eligible (within same Capacity Zone where nested export-constrained Capacity Zone is located)

	Nested Export-Constrained Capacity Zone	Ineligible	Ineligible	Ineligible	Eligible (within same Capacity Zone)

III.15.2.9. Self-Supplied Capacity.

Where a load serving entity elects to designate all or a portion of its Capacity Load Obligation as self-supplied, the load serving must make such designation to the ISO during the self-supply designation window, as published in the Capacity Auction Calendar on the ISO's website. The load serving entity's designation shall specify the MW amount and Lead Market Participant providing the self-supplied capacity. During the Annual Capacity Auction Offer Window, the Lead Market Participant supplying such capacity shall confirm the load serving entity's self-supply designation by specifying each Self-Supplied Capacity Resource and the MW amount of self-supplied capacity in its Capacity Offer. A Generating Capacity Resource or an Import Capacity Resource may be designated as a Self-Supplied Capacity Resource. A Distributed Energy Capacity Resource may only designate its net injection capability as a Self-Supplied Capacity Resource. All self-supplied capacity shall be subject to the eligibility and locational requirements in this Section III.15.2.9. If designated as a Self-Supplied Capacity Resource the resource will clear in the Annual Capacity Auction as described in Section III.15.4 and, with the exception of demand programs for Self-Supplied Capacity Resources, shall offset an equal amount of the load serving entity's Capacity Load Obligation in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Capacity Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.15.2. All designations as a Self-Supplied Capacity Resource in the Annual Capacity Auction qualification process are binding.

III.15.2.9.1. Self-Supplied Capacity Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied Capacity Resource, it shall also maintain its status as a Generating Capacity Resource, Import Capacity Resource, or Distributed Energy Capacity Resource and must satisfy the Annual Capacity Auction qualification process requirements set forth in the remainder of Section III.15.2 applicable to that resource type, in addition to the requirements of this Section III.15.2.9.1. Where a Capacity Offer composed of separate resources is submitted for a Self-Supplied Capacity Resource, all of the requirements and deadlines specified in Section III.15.2.8 shall apply to that offer, in addition to the requirements of this Section III.15.2.9. The total quantity of capacity that a load serving entity designates as self-supplied capacity

may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period, which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied Capacity Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.15.2.9.2. Locational Requirements for Self-Supplied Capacity Resources.

In order to participate in the Annual Capacity Auction as a Self-Supplied Capacity Resource for a load in an import-constrained Capacity Zone, the Self-Supplied Capacity Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied Capacity Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Annual Capacity Auction as a Self-Supplied Capacity Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied Capacity Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.15.2.10. Publication of Annual Qualified Capacity Values for Annual Capacity Auction.

The ISO shall provide Annual Qualified Capacity values to Lead Market Participants of each Capacity Resource participating in an Annual Capacity Auction one business day before the opening of the Annual Capacity Auction Offer Window.

III.15.2.11. Publication of Offer Information.

(a) For each Capacity Offer, the quantity and Load Zone (or interface, as applicable) in which the resource is located will be published to the ISO's website no later than 15 days after the Annual Capacity Auction is conducted.

(b) For Capacity Offers from Import Capacity Resources, the name of submitter, quantity, and interface shall be published to the ISO's website no later than 15 days after the Annual Capacity Auction is conducted.

(c) The name of each Lead Market Participant submitting Capacity Offers, as well as the number of Capacity Offers submitted by each Lead Market Participant, shall be published to the ISO's website no later than 15 calendar days after the issuance of Advisory Qualified Capacity Values. Authorized Persons

of Authorized Commissions will be provided confidential access to full information about posted Capacity Offers upon request pursuant to Section 3.3 of the ISO New England Information Policy.

III.15.3. Capacity Resource Accreditation.

Pursuant to the provisions of this Section III.15.3, the ISO shall determine a summer Qualified Capacity, a winter Qualified Capacity, an Annual Qualified Capacity and, where applicable, a Monthly Qualified Capacity for each Generating Capacity Resource, Import Capacity Resource, Demand Capacity Resource, and Distributed Energy Capacity Resource. A Capacity Resource's Seasonal Qualified Capacity Values shall not exceed its seasonal Capacity Network Resource Interconnection Service or equivalent, or Capacity Network Import Interconnection Service, as applicable. Qualified Capacity for resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall not exceed the resource's highest previously received Capacity Supply Obligation unless the resource has demonstrated and qualified the additional capacity pursuant to Section III.15.2.4.1.

Qualified Capacity values for resources that have never previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall be calculated pursuant to Section III.15.3.1. Qualified Capacity for resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall be calculated pursuant to Sections III.15.3.2 through III.15.3.5.

III.15.3.1. Qualified Capacity for Resources Never Previously Counted as Capacity.

III.15.3.1.1. Resources Never Previously Counted as Capacity.

The summer and winter Qualified Capacity of a Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or is otherwise treated as such pursuant to the terms of this Section III.15, shall be determined in accordance with the capacity demonstration requirements set forth in Section III.15.2.6, as specified below.

To determine the Seasonal Qualified Capacity Values of a Generating Capacity Resource that is not an Intermittent Power Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant to Section III.15.2.6(c)(i), the ISO shall use the Section III.1.5.1.2(c) audit results. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3 and III.15.3.2.4, respectively.

To determine the Seasonal Qualified Capacity Values of a Generating Capacity Resource that is an Intermittent Power Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant Section III.15.2.6(c)(ii), the ISO shall use the Section III.1.5.1.3 audit results. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3 and Section III.15.3.2.4, respectively.

To determine the Seasonal Qualified Capacity Values of an Active Demand Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(iii), the ISO shall use the Section III.1.5.1.3.1 audit results. To determine the Seasonal Qualified Capacity Values of a Demand Capacity Resource other than an Active Demand Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(iv), the ISO shall use the Section III.15.7.1.5.4 audit results. The annual and Monthly Qualified Capacity of such resources shall be determined pursuant to Sections III.15.3.4.2 and III.15.3.4.3, respectively.

To determine the Seasonal Qualified Capacity Values of a Distributed Energy Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(v), the ISO shall use the audit results specified therein for the corresponding asset type. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to III.15.3.5.2 and III.15.3.5.3, respectively.

To determine the Seasonal Qualified Capacity Values of an Import Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant Section III.15.2.6(c)(vi), the ISO shall use the performance data results specified therein. The annual and monthly Qualified Capacity of such a resource shall be determined pursuant to III.15.3.3.

To determine the Seasonal Qualified Capacity Values of a resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and that has elected to demonstrate commercial capacity pursuant Section III.15.2.6(d), the ISO shall use the values developed pursuant to Section III.15.2.6(d). The annual Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3, Section III.15.3.4.2, or Section III.15.3.5.2, as applicable to

the relevant resource type. The Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.4, III.15.3.4.3, or Section III.15.3.5.3, as applicable to the relevant resource type.

III.15.3.2 Qualified Capacity for Generating Capacity Resources.

The summer, winter, annual, and monthly Qualified Capacity for Generating Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.2.

III.15.3.2.1. Summer Qualified Capacity.

(a) For the purpose of Annual Capacity Auction qualification, the summer Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the Capacity Demonstration Deadline each year, with only positive summer ratings included in the median calculation. Where a Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Generating Capacity Resource shall be equal to the median of all the Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the Capacity Demonstration Deadline of each year, with only positive summer ratings included in the median calculation.

(b) For the purpose of Annual Capacity Auction qualification, the summer Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the average of the median of the Intermittent Power Resource's net output during Summer Intermittent Reliability Hours for each of the previous five summer periods. If there are fewer than five full summer periods since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation, the summer Qualified Capacity of such resource shall be the average of the median of the Intermittent Power Resource's net output during Summer Intermittent Reliability Hours in each of the previous summer periods, or portion thereof, since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation. The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which there was a system-wide Capacity Scarcity Condition, and for Intermittent Power Resources in an import-constrained Capacity Zone, all summer period hours in which there was a Capacity Scarcity Conditions in that Capacity Zone.

III.15.3.2.2. Winter Qualified Capacity.

(a) For the purpose of Annual Capacity Auction qualification, the winter Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the Capacity Demonstration Deadline of each year, with only positive winter ratings included in the median calculation. Where a Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Generating Capacity Resource shall be equal to the median of all the Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the Capacity Demonstration Deadline of each year, with only positive winter ratings included in the median calculation.

(b) For the purpose of Annual Capacity Auction qualification, the winter Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the average of the median of the Intermittent Power Resource's net output during Winter Intermittent Reliability Hours for each of the previous five summer periods. If there are fewer than five full summer periods since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation, the winter Qualified Capacity of such resource shall be the average of the median of the Intermittent Power Resource's net output during Winter Intermittent Reliability Hours in each of the previous winter periods, or portion thereof, since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation. The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which there was a system-wide Capacity Scarcity Condition, and for Intermittent Power Resources in an import-constrained Capacity Zone, all winter period hours in which there was a Capacity Scarcity Conditions in that Capacity Zone.

III.15.3.2.3. Annual Qualified Capacity.

The Annual Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The Annual Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.15.3.2.4. Monthly Qualified Capacity.

The Monthly Qualified Capacity of a Generating Capacity Resource shall be the resource's most recent Seasonal Claimed Capability value for the season applicable to the relevant month; for those Generating Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

III.15.3.3. Qualified Capacity for Import Capacity Resources.

The summer, winter, annual, and monthly Qualified Capacity of an Import Capacity Resource backed by an External Control Area shall be based on the values and data submitted during the qualification process, subject to ISO review and verification. The summer, winter, annual, and monthly Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be based on the data submitted during the qualification process, subject to ISO review and verification, and calculated based on the summer and winter Qualified Capacity of the resources underlying the Import Capacity Resource, in accordance with Sections III.15.3.2.1 and III.15.3.2.2.

III.15.3.4. Qualified Capacity for Demand Capacity Resources.

The summer, winter, annual, and monthly Qualified Capacity for Demand Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.4.

III.15.3.4.1. Summer and Winter Qualified Capacity.

(a) For Demand Capacity Resources composed of Energy Efficiency measures, the summer (or winter, as applicable) Qualified Capacity shall equal the sum of the summer (or winter, as applicable) demand reduction values of the installed Energy Efficiency measures as of the Capacity Demonstration Deadline (excluding any capacity that will retire or deactivate, or whose Measure Life will expire, prior to the start of the applicable season of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses).

(b) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the summer and winter Qualified Capacity shall equal the median of the resource's Seasonal DR Audit value or Passive DR Audit value from the five most recent years, for the relevant season, increased by average avoided peak transmission and distribution losses. Where a Demand Capacity Resource has fewer than five summer or winter Seasonal Audit Values, as applicable, then the summer (or winter) Qualified Capacity for that Demand Capacity Resource shall be equal to the median of all the resource's previous

summer (or winter) Seasonal Audit Values, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation.

III.15.3.4.2. Annual Qualified Capacity.

The Annual Qualified Capacity of a Demand Capacity Resource shall equal the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.15.3.4.3 Monthly Qualified Capacity.

The Monthly Qualified Capacity of a Demand Capacity Resource, other than a resource composed of Energy Efficiency measures, shall equal its most recent Seasonal DR Audit value or Passive DR Audit value for the season applicable to the relevant month; for those Demand Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

The Monthly Qualified Capacity of a Demand Capacity Resource composed of Energy Efficiency measures shall equal the most recently-determined summer or winter demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire, deactivate, or whose Measure Life will expire, prior to the start of the relevant Obligation Month, and increased by average avoided peak transmission and distribution losses).

III.15.3.5. Qualified Capacity of Distributed Energy Capacity Resources.

The summer, winter, annual, and monthly Qualified Capacity for Distributed Energy Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.5.

III.15.3.5.1. Summer and Winter Qualified Capacity.

The summer (or winter, as applicable) Qualified Capacity of a Distributed Energy Capacity Resource that is not an Intermittent Power Resource shall equal the median of the resource's summer (or winter) Seasonal Audit Value from the five most recent years, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation. Where a Distributed Energy Capacity Resource has fewer than five summer (or winter) Seasonal Audit Values, then the summer (or winter) Qualified Capacity for that Distributed Energy Capacity Resource shall be

equal to the median of the resource's previous summer (or winter) Seasonal Audit Values, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation.

The summer or winter Qualified Capacity of Distributed Energy Capacity Resources that are Intermittent Power Resources shall be determined in accordance with the rules for Generating Capacity Resources that are Intermittent Power Resources in Section III.15.3.2.

III.15.3.5.2. Annual Qualified Capacity.

Annual Qualified Capacity for a Distributed Energy Capacity Resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, unless the Distributed Energy Capacity Resource is an Intermittent Power Resource, in which case the Annual Qualified Capacity shall be equal to the resource's summer Qualified Capacity.

III.15.3.5.3. Monthly Qualified Capacity.

The Monthly Qualified Capacity of a Distributed Energy Capacity Resource shall equal the most recent Seasonal DECR Audit for the season applicable to the relevant month; for those Distributed Energy Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

III.15.3.6. Adjustment for Significant Decreases in Capacity.

For a Generating Capacity Resource, Import Capacity Resource backed by an External Resource, Distributed Energy Capacity Resource, or Demand Capacity Resource, if the most recent summer Seasonal Claimed Capability rating, summer season Import Capacity Resource performance data submitted pursuant to Section III.15.2.1.1.1, summer Seasonal DECR Audit Value, summer Seasonal DR Audit Value, or summer Passive DR Audit Value as of the Annual Capacity Auction's Capacity Demonstration Deadline is below the resource's Qualified Capacity by more than the threshold defined in the following formula:

$$Threshold = min[max(10\% \times QC_{Summer}, 2\ MW), 10\ MW]$$

Where,

QC_{Summer} = the resource's summer Qualified Capacity

then the Lead Market Participant must elect one of the two treatments set forth in this Section III.15.3.6 by the close of the Seasonal Qualified Capacity Challenge and Restoration Plan Submission Window. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.15.3.6(b) and fails to meet the associated requirements, then the treatment described in Section III.15.3.6(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Annual Capacity Auction only, to have the resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability rating, summer Seasonal DECR Audit Value, Seasonal DR Audit Value, or Passive DR Audit Value as of the Capacity Demonstration Deadline, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) A Lead Market Participant may elect: (i) to submit a restoration plan describing the measures that will be taken and showing that the Generating Capacity Resource, Import Capacity Resource backed by an External Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section III.15.3.2, Section III.15.3.3, Section III.15.3.4, or Section III.15.3.5 by the start of the relevant Capacity Commitment Period; and (ii) to have the Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section III.15.3.2, Section III.15.3.3, Section III.15.3.4, or Section III.15.3.5 for the Annual Capacity Auction. The ISO shall review submitted restoration plans in accordance with the requirements and timelines set forth in Section III.15.2.7.

III.15.3.7. Resources Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where a Generating Capacity Resource (other than an Intermittent Power Resource), Demand Capacity Resource, or Import Capacity Resource has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.15.3, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, in accordance with Section III.15.2.8; or (ii) have its Annual Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

Where a Distributed Energy Capacity Resource (other than an Intermittent Power Resource) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this

Section III.15.3, then that resource must have its Annual Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

III.15.4. Annual Capacity Auction.

III.15.4.1 Capacity Offers.

Lead Market Participants submitting Capacity Offers in the Annual Capacity Auction shall submit Capacity Offers for the Capacity Commitment Period associated with the Annual Capacity Auction as specified in this Section III.15.4.1.

(a) Each Capacity Offer shall be associated with a Capacity Resource for which an Annual Qualified Capacity value has been established for the Annual Capacity Auction through the Annual Capacity Auction qualification process set forth in Sections III.15.2 and III.15.3.

(b) Capacity Offers must be submitted during the Annual Capacity Auction Offer Window, the dates of which will be specified as published in the Capacity Auction Calendar. Capacity Offers are not considered final until the close of the Annual Capacity Auction Offer Window and may be amended or corrected as necessary until such time as the window closes.

(c) If a Lead Market Participant fails to submit a Capacity Offer for a resource subject to the requirements of Section III.A.22.1, the ISO shall enter a Capacity Offer for the resource into the Annual Capacity Auction in accordance with Section III.A.22.1(d).

(d) Each Capacity Offer must specify at least one price-quantity pair, which consists of one price, denominated in $/kW-month to an accuracy of at most three digits to the right of the decimal point, and a quantity value, expressed in MW to an accuracy of up to three decimal places. The Capacity Offer may specify up to ten price-quantity pairs, where each such pair represents the total amount of capacity offered from the Capacity Resource at the price specified. If more than one price-quantity pair is submitted, the price-quantity pairs must specify prices and quantity values in such a way that, when the price-quantity pairs are ordered from lowest price to highest price, the quantity value in each price-quantity pair increases with each successive, higher-priced price-quantity pair. The price-quantity pair with the greatest specified price must include the Capacity Resource's total Annual Qualified Capacity. The Capacity Offer must not contain any offer prices less than $0.00/kW-month or greater than the Capacity Auction Offer Price Cap, unless otherwise allowed pursuant to Section III.A.22.2.3 and subsection (e) of this Section III.15.4.1 or required by Section III.A.21 and subsection (f) of this Section III.15.4.1. The Capacity Offer must not specify a total MW quantity value that exceeds the Capacity Resource's Annual Qualified Capacity.

(e) A price-quantity pair in a Capacity Offer must not specify a price above the Capacity Offer Price Threshold, except under the following circumstances:

(i) the Lead Market Participant for the Capacity Resource submitted the price-quantity pair to the Internal Market Monitor as part of a Proposed Capacity Offer, pursuant to Section III.A.22.2.2;

(ii) the Internal Market Monitor determined an Allowable Capacity Offer Price relative to the price-quantity pair pursuant to Section III.A.22.2.3; and

(iii) the specified price in the Capacity Offer does not exceed the price specified in the price-quantity pair reviewed by the Internal Market Monitor.

(f) For capacity included in a Capacity Offer that is subject to a Capacity Offer Floor Price pursuant to Section III.A.21.3, the price specified must not be less than the Capacity Offer Floor Price.

(g) A Capacity Offer may specify a Rationing Minimum Limit up to which the offer may not be rationed and must be accepted or rejected in whole. Without such indication, offers shall be rationable up to the total MW quantity in the offer that is priced at or below the Capacity Offer Price Threshold, subject to the auction clearing constraint described in Section III.15.4.2.2(d). The lowest priced price-quantity pair in a Capacity Offer that specifies a Rationing Minimum Limit must specify a quantity value equal to or greater than the specified Rationing Minimum Limit. Notwithstanding the foregoing, a Capacity Offer for an Import Capacity Resource may only specify a Rationing Minimum Limit pursuant to this subsection (g) if the Import Capacity Resource is associated with an Elective Transmission Upgrade, as described in Section III.15.2.1.1.1.

(h) If the Capacity Offer specifies any price above the Capacity Offer Price Threshold, the Capacity Offer may elect to have the Above-Threshold Offer Segment be treated as rationable, subject to any Rationing Minimum Limit specified pursuant to subsection (g). Without such an election, the Above-Threshold Offer Segment will be treated as non-rationable and accepted or rejected in whole. Notwithstanding the foregoing, a Capacity Offer for an Import Capacity Resource may only elect rationability for the Above-Threshold Offer Segment pursuant to this subsection (h) if the Import

Capacity Resource is associated with an Elective Transmission Upgrade, as described in Section III.15.2.1.1.1.

(i) In order to give effect to a self-supply designation made by a load serving entity pursuant to Section III.15.2.9 for any portion of the Capacity Resource's Annual Qualified Capacity, the Capacity Offer for such resource must (i) identify the load serving entity for which its capacity will serve as self-supplied capacity and the MW quantity of self-supplied capacity and (ii) include a price-quantity pair with an offer price of $0.00/kW-month that includes the amount of such capacity, unless such capacity is subject to a Capacity Offer Floor Price. If the self-supplied capacity is subject to a Capacity Offer Floor Price, then the price specified in the price-quantity pair including the self-supplied capacity must equal the Capacity Offer Floor Price.

(j) A Capacity Offer for a Generating Capacity Resource with a contract to export capacity during the Capacity Commitment Period must specify an Export Offer Segment and the interface over which the Export Offer Segment will be exported.

(k) A Lead Market Participant for a Capacity Resource that is subject to delayed deactivation pursuant to Sections II.52 and II.53 shall not enter a Capacity Offer for any capacity supplied by the Capacity Resource that is subject to delayed deactivation. The ISO shall enter such Capacity Resource's capacity subject to delayed deactivation into the Annual Capacity Auction at a price of $0.00/kW-month.

(l) If a prior multi-year Capacity Supply Obligation and Capacity Clearing Price election for the Capacity Resource had been made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 for a Forward Capacity Auction, the Capacity Offer submitted for such Capacity Resource must include a price-quantity pair with an offer price of $0.00/kW-month that includes the total amount of the resource's capacity that cleared subject to such election.

III.15.4.2. Conduct of the Annual Capacity Auction.

The ISO shall determine Capacity Supply Obligations and Capacity Clearing Prices for the Capacity Commitment Period by conducting the Annual Capacity Auction as described in this Section III.15.4.2.

III.15.4.2.1. Replacement of Specified Prices for Mitigation Purposes.

After the Annual Capacity Auction Offer Window, the ISO shall replace specified prices in submitted Capacity Offers as necessary, pursuant to Section III.A.22.2.4(c). Any such adjusted Capacity Offers shall be inputs for the Annual Capacity Auction.

III.15.4.2.2. Clearing of the Annual Capacity Auction.

(a) In determining Capacity Supply Obligations and Capacity Clearing Prices, the ISO shall employ an optimization algorithm that is designed to maximize social surplus in order to clear Capacity Offers, capacity entered into the auction by the ISO as described in Section III.15.4.1(k), and any Proxy Capacity Offers against the capacity demand curves calculated in accordance with Section III.15.1.1. In clearing Capacity Offers, the optimization algorithm shall take into account, as applicable, the inputs and constraints set forth in this Section III.15.4.2.2.

(b) The optimization algorithm shall take into account the following: (i) all price-quantity pairs in Capacity Offers for the Annual Capacity Auction submitted pursuant to Section III.15.4.1, subject to any adjustments made pursuant to Section III.15.4.2.1 and the constraint described in subsection (c) of this Section III.15.4.2.1; (ii) any Rationing Minimum Limits and rationability elections specified in Capacity Offers pursuant to Section III.15.4.1(g) and Section III.15.4.1(h), respectively; (iii) capacity from a Capacity Resource subject to delayed deactivation pursuant to Sections II.52 and II.53 at a default price of $0.00/kW-month; (iv) the set of distinct Capacity Zones determined to be modeled in the Annual Capacity Auction pursuant to Section III.12.4; (v) the System-Wide Capacity Demand Curve calculated in accordance with Section 15.1.1.1; (vi) any Capacity Zone Demand Curves for import-constrained and export-constrained Capacity Zones, calculated in accordance with Sections 15.1.1.2 and 15.1.1.3, respectively; (vii) external interface limits calculated pursuant to Section III.12.10; and (viii) any Proxy Capacity Offers for the Annual Capacity Auction as determined pursuant to Section III.A.24.7, which shall be treated as non-rationable.

(c) The optimization algorithm shall not take into account price-quantity pairs in Capacity Offers that specify a price that exceeds the Capacity Auction Offer Price Cap.

(d) Capacity entered into the Annual Capacity Auction at a price of $0.00/kW-month shall clear the auction.

(e) A Capacity Offer that specifies a Rationing Minimum Limit pursuant to Section III.15.4.1(g) shall not clear at quantities less than the specified Rationing Minimum Limit, and Above-Threshold Offer

Segments that are non-rationable pursuant to Section III.15.4.1(h) shall not clear at quantities less than the MW quantity of the segment.

(f) For an Export Offer Segment specified in a Capacity Offer that indicates a Generating Capacity Resource's contract to export capacity over an external interface connected to an import-constrained Capacity Zone from another Capacity Zone, or over an external interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone, the ISO shall model the Export Offer Segment as though that quantity of capacity were located in the Capacity Zone where the external interface identified in the Capacity Offer is located and adjust Capacity Zone Demand Curves as necessary to reflect such modeling.

(g) In determining the clearing result that accounts for auction inputs and satisfies all applicable constraints, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including clearing results where a Capacity Offer with a specified price below the Capacity Clearing Price does not clear.

(h) Where the clearing of the Annual Capacity Auction either system-wide or in a single Capacity Zone results in a tie (that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs), the following rules shall apply in sequence, as necessary, to determine clearing: (i) if multiple Capacity Offers may be rationed, they will be rationed proportionately; and (ii) the Capacity Offer associated with the Lead Market Participant having the lower market share in the capacity auction shall be cleared.

(i) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be the price specified by the System-Wide Capacity Demand Curve for the system-wide capacity entered into the Annual Capacity Auction that maximizes social surplus. In no case, however, shall the Capacity Clearing Price for the Rest-of-Pool Capacity Zone be less than the highest price specified in an offer for capacity that clears the auction, excluding any capacity that, due to its specified price, would not have cleared but for the fact that it is located within an import-constrained Capacity Zone that has a cleared quantity of capacity equal to or less than the truncation point for the zone's Capacity Zone Demand Curve.

(j) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an import-constrained Capacity Zone shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the import-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone; and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the import-constrained Capacity Zone and that clears the auction.

(k) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the export-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Rest-of-Pool Zone; and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the export-constrained Capacity Zone and that clears the auction.

(l) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an export-constrained Capacity Zone that is a nested export-constrained Capacity Zone, shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the export-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Capacity Zone in which the nested Capacity Zone is located; and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the export-constrained Capacity Zone and that clears the auction.

(m) The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for an import-constrained Capacity Zone shall not exceed the Capacity Auction Offer Price Cap. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

(n) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an interface between the New England Control Area and an external Control Area shall be equal to:

(i) if the quantity of capacity over the external interface that clears the auction is equal to the external interface limit for such interface, the highest price specified in a Capacity Offer for capacity that is supplied from a resource offering capacity over such external interface and that clears the auction; or

(ii) if the quantity of capacity over the external interface that clears the auction is less than the external interface limit for such interface, the Capacity Clearing Price for the Capacity Zone associated with the external interface.

III.15.4.2.3. Results of the Annual Capacity Auction.

(a) Annual Capacity Supply Obligations shall be awarded to Capacity Resources in accordance with the results of the Annual Capacity Auction clearing mechanics described in Section III.15.4.2.2. For Intermittent Power Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.15.2) shall be adjusted based on the winter Qualified Capacity as determined pursuant to Section III.15.3.2.2. Additional Capacity Supply Obligations may be awarded in accordance with Section III.15.4.2.4.

(b) The Capacity Clearing Prices in each Capacity Zone modeled in the Annual Capacity Auction shall be the clearing prices determined as a result of the Annual Capacity Auction clearing mechanics described in Section III.15.4.2.2.

III.15.4.2.4. Additional Clearing of Auction in the Event of Cleared Proxy Offers.

If any Proxy Capacity Offer entered into the Annual Capacity Auction clears and receives a Capacity Supply Obligation, the ISO shall conduct an additional run of the auction. This additional run shall use the same methodology described in Section III.15.4.2.2, except that the additional run shall (i) exclude all Proxy Capacity Offers and (ii) enter all other capacity that cleared in the primary run of the Annual Capacity Auction at a price of $0.00/kW-month. The additional run of the auction shall not affect the Capacity Clearing Prices of the primary run of the Annual Capacity Auction pursuant to Section III.15.4.2.2. Capacity (other than capacity still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receives a Capacity Supply Obligation as a result of the primary run of the Annual Capacity Auction shall be paid the Capacity

Clearing Price in the Capacity Zone associated with the capacity during the associated Capacity Commitment Period. Where the additional run of the auction procures additional capacity, that additionally procured capacity shall be paid the price resulting from the additional run in the Capacity Zone associated with that additional capacity during the associated Capacity Commitment Period, and such price shall be equal to or greater than the price resulting from the primary run of the Annual Capacity Auction in that Capacity Zone.

III.15.4.3. Publication of Annual Capacity Auction Results.

As soon as practicable after the Annual Capacity Auction is complete, the ISO shall publish the results of that Annual Capacity Auction publicly on its website, including the set of Capacity Zones modeled in the auction, the Capacity Clearing Prices in each of those Capacity Zones, and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. The published information shall identify Proxy Capacity Offers that cleared, if any, in the primary run of the Annual Capacity Auction.

III.15.5. Monthly Reconfiguration Auctions.

For each Capacity Commitment Period, the ISO shall conduct Monthly Reconfiguration Auctions as described in this Section III.15.5. Monthly Reconfiguration Auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in the Monthly Reconfiguration Auctions. Each reconfiguration auction shall use a static double auction (respecting the interface limits and capacity requirements modeled as specified in Section III.15.5.1) to clear supply offers (i.e., offers to assume a Capacity Supply Obligation) and demand bids (i.e., bids to shed a Capacity Supply Obligation) for each Capacity Zone included in the reconfiguration auction. Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected. Resources that are able to meet the requirements in other Capacity Zones shall be allowed to clear to meet such requirements, subject to the constraints modeled in the auction.

III.15.5.1. Capacity Zones Included in Monthly Reconfiguration Auctions.

Each Monthly Reconfiguration Auction associated with a Capacity Commitment Period shall include each of, and only, the Capacity Zones and external interfaces modeled in the Annual Capacity Auction for that Capacity Commitment Period in accordance with Section III.15.4.2.2.

III.15.5.2. Participation in Monthly Reconfiguration Auctions.

Each supply offer and demand bid in a Monthly Reconfiguration Auction must be associated with a specific resource and must satisfy the requirements of this Section III.15.5.2. All resource types may submit supply offers and demand bids in reconfiguration auctions. In accordance with Section III.A.13.2, supply offers and demand bids submitted for Monthly Reconfiguration Auctions shall not be subject to mitigation by the Internal Market Monitor. Offers composed of separate resources may not participate in reconfiguration auctions. Resources with capacity subject to delayed deactivation pursuant to Sections II.52 and II.53 may not participate in reconfiguration auctions, unless otherwise authorized pursuant to the terms of a cost-of-service agreement of the type described in Section II.54.1. Participation in any reconfiguration auction is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of the offer and bid deadline. The offer and bid deadline for each Monthly Reconfiguration Auction shall be announced by the ISO no later than 10 Business Days prior to that deadline. Upon issuance of the monthly bilateral results for the associated Obligation Month, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that monthly auction, as calculated pursuant to this Section III.15.5.2.

III.15.5.2.1. Supply Offers in Monthly Reconfiguration Auctions.

(a) All supply offers in Monthly Reconfiguration Auctions shall be submitted by the Lead Market Participant, and shall specify the resource, the amount of capacity offered in MW, and the price, denominated in $/kW-month.

(b) A resource may not submit a supply offer for a Monthly Reconfiguration Auction unless a Monthly Qualified Capacity value has been established for the resource for the month associated with the Monthly Reconfiguration Auction pursuant to the qualification processes described in Sections III.15.2 and III.15.3.

(c) The amount of capacity up to which a resource may submit a supply offer in a Monthly Reconfiguration Auction shall be the difference (but in no case less than zero) between (i) the resource's Monthly Qualified Capacity for the month associated with the auction, as determined pursuant to Section III.15.3 during the most recent qualification process for the resource; and (ii) the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for that month.

III.15.5.2.2. Demand Bids in Monthly Reconfiguration Auctions.

(a) All demand bids in Monthly Reconfiguration Auctions shall be submitted by the Lead Market Participant and shall specify the amount of capacity bid in MW and the price, denominated in $/kW-month.

(b) To submit a demand bid in a Monthly Reconfiguration Auction, a resource must have a Capacity Supply Obligation for the month associated with that Monthly Reconfiguration Auction.

(c) Where capacity associated with a Self-Supplied Capacity Resource that cleared in the Annual Capacity Auction for the Capacity Commitment Period is offered in a Monthly Reconfiguration Auction, a resource acquiring a Capacity Supply Obligation in that Monthly Reconfiguration Auction shall not as a result become a Self-Supplied Capacity Resource.

(d) Each demand bid submitted to the ISO for a Monthly Reconfiguration Auction shall be no greater than the amount of the resource's capacity that is already obligated for the month associated with that Monthly Reconfiguration Auction as of the offer and bid deadline for the auction.

III.15.5.3. Clearing Offers and Bids in Monthly Reconfiguration Auctions.

All supply offers and demand bids are rationable and may be cleared in whole or in part in Monthly Reconfiguration Auctions.

III.15.5.4. Conduct of Monthly Reconfiguration Auctions.

Prior to each month in the Capacity Commitment Period, the ISO shall conduct a Monthly Reconfiguration Auction for whole-month capacity commitments during that month. For each Monthly Reconfiguration Auction, the ISO shall employ an optimization algorithm that is designed to maximize social surplus in order to clear the supply offers against demand bids submitted for the auction. The truncation points for import-constrained Capacity Zones and export-constrained Capacity Zones specified in Section III.15.1.1.2 and Section III.15.1.1.3 and external interface limits established pursuant to Section III.12 shall be modeled as constraints in the auction. The System-Wide Capacity Demand Curve is not modeled in Monthly Reconfiguration Auctions.

III.15.5.5. Adjustment to Capacity Supply Obligations.

For each supply offer that clears in a Monthly Reconfiguration Auction, the resource's Capacity Supply Obligation for the month associated with the auction shall be increased by the amount of capacity that clears. For each demand bid that clears in a Monthly Reconfiguration Auction, the resource's Capacity Supply Obligation for the month associated with the auction shall be decreased by the amount of capacity that clears.

III.15.6. Bilateral Capacity Contracts.

Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals and Capacity Load Obligation Bilaterals in accordance with this Section III.15.6, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation. To the extent necessary for the ISO's review and approval of any of the bilateral contracts described in this Section III.15.6, the ISO shall apply the Capacity Zones and external interfaces modeled as inputs and constraints in the Annual Capacity Auction for the applicable Capacity Commitment Period, as described in Section III.15.4.2.2. Resources with capacity subject to delayed deactivation pursuant to Sections II.52 and II.53 may not participate in Capacity Supply Obligation Bilaterals, unless otherwise authorized pursuant to the terms of a cost-of-service agreement of the type described in Section II.54.1.

III.15.6.1. Capacity Supply Obligation Bilaterals.

A Capacity Transferring Resource having a Capacity Supply Obligation and seeking to shed that obligation may enter into a Capacity Supply Obligation Bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part, to a Capacity Acquiring Resource, or portion thereof, for a whole-month period during the Capacity Commitment Period, as described in this Section III.15.6.1.

III.15.6.1.1. Terms of and Participation in Capacity Supply Obligation Bilaterals.

(a) Capacity Supply Obligation Bilaterals are available for monthly periods, and a Capacity Supply Obligation Bilateral must be coterminous with a calendar month.

(b) The qualification of Capacity Acquiring Resources for participation in Capacity Supply Obligation Bilaterals is determined in the same manner as the qualification of resources submitting supply offers for Monthly Reconfiguration Auctions as specified in Section III.15.5.2.1(b). A resource that does not have a Monthly Qualified Capacity value established for the month covered by the Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that month.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the monthly Capacity Supply Obligation of the Capacity Transferring Resource. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the amount of unobligated Monthly Qualified Capacity of the Capacity Acquiring Resource for the month covered by the Capacity Supply Obligation Bilateral. For the purpose of this subsection (c), unobligated Monthly Qualified Capacity refers to the Monthly Qualified Capacity that was

determined pursuant to Section III.15.3 in the most recent qualification process for the resource prior to the submission of the Capacity Supply Obligation Bilateral to the ISO and that is not subject to a Capacity Supply Obligation.

(d) A resource, or a portion thereof, that has been designated as a Self-Supplied Capacity Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied Capacity Resource as a result of the transaction.

(e) Capacity Supply Obligation Bilaterals are allowed between a Capacity Transferring Resource and a Capacity Acquiring Resource that are located within different Capacity Zones and across external interfaces modeled as part of the Annual Capacity Auction for the Capacity Commitment Period of the relevant monthly period, subject to the transmission interface limits between Capacity Zones and external interface limits, as described in Section III.15.6.1.4(b).

(f) Participation in any Capacity Supply Obligation Bilateral is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of submission to the ISO.

III.15.6.1.2. Timing of Submission and Prior Notification to the ISO.

The Lead Market Participant for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Capacity Supply Obligation Bilaterals in the Capacity Auction Calendar. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than the end of the relevant submittal window.

III.15.6.1.3. Contents of Submission to the ISO.

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, denominated in $/kW-

month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of $0.00/kW-month.

III.15.6.1.4. ISO Review.

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral and shall reject the Capacity Supply Obligation Bilateral if any of the submission and participation requirements described in this Section III.15.6.1 are not met. For a Capacity Supply Obligation Bilateral submitted before the relevant submittal window opens, this review shall occur once the submittal window opens. For a Capacity Supply Obligation Bilateral submitted after the submittal window opens, this review shall occur upon submission.

(b) After the close of the submittal window, the ISO shall conduct a review to determine the deliverability of the submitted Capacity Supply Obligation Bilaterals. In its review, the ISO shall model as constraints the truncation points for import-constrained Capacity Zones and export-constrained Capacity Zones specified in Sections III.15.1.1.2 and III.15.1.1.3 and external interface limits established pursuant to Section III.12 for the applicable Capacity Commitment Period. The ISO shall reject Capacity Supply Obligation Bilaterals that are not fully deliverable up to their specific MW values without violating transmission transfer limits between Capacity Zones or external transfer limits. Transactions will only be accepted or rejected in their entirety. The ISO shall approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected, the Lead Market Participant for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the basis for such rejection.

(c) Each Capacity Supply Obligation Bilateral shall be subject to a financial assurance review by the ISO. If the Capacity Transferring Resource and the Capacity Acquiring Resource are not both in compliance with all applicable provisions of the ISO New England Financial Assurance Policy, including those regarding Capacity Supply Obligation Bilaterals, the ISO shall reject the Capacity Supply Obligation Bilateral.

III.15.6.1.5. Approval.

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource for the month covered by the Capacity Supply Obligation Bilateral shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply

Obligation of the Capacity Acquiring Resource for the month covered by the Capacity Supply Obligation Bilateral shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

III.15.6.2. Capacity Load Obligations Bilaterals.

A Capacity Load Obligation Transferring Participant seeking to shed its Capacity Load Obligation may enter into a Capacity Load Obligation Bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone to a Capacity Load Obligation Acquiring Participant seeking to acquire a Capacity Load Obligation, as described in this Section III.15.6.2.

III.15.6.2.1. Terms of and Participation in Capacity Load Obligation Bilaterals.

A Capacity Load Obligation Bilateral must be in whole calendar month increments, may not exceed one year in duration, and must begin and end within the same Capacity Commitment Period. A Capacity Load Obligation Transferring Participant will be permitted to transfer, and a Capacity Load Obligation Acquiring Participant will be permitted to acquire, a Capacity Load Obligation if after entering into a Capacity Load Obligation Bilateral and submitting related information to the ISO within the specified submittal time period, the ISO approves such Capacity Load Obligation Bilateral.

III.15.6.2.2. Timing of Submission to the ISO.

Either the Capacity Load Obligation Transferring Participant or the Capacity Load Obligation Acquiring Participant may submit a Capacity Load Obligation Bilateral to the ISO. All Capacity Load Obligation Bilaterals must be submitted to the ISO in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial daily settlements of payments and charges associated with the Annual Capacity Market for the first month of the term of the Capacity Load Obligation Bilateral, a Capacity Load Obligation Bilateral must be submitted to the ISO no later than 12:00 p.m. on the first Business Day of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

III.15.6.2.3. Contents of Submission to the ISO.

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following: (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant

and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

III.15.6.2.4. ISO Review.

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section III.15.6.2 are not met.

III.15.6.2.5. Approval.

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral for the period covered by the bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral for the period covered by the bilateral.

III.15.7. Obligations of Capacity Suppliers.

Resources assuming a Capacity Supply Obligation through an Annual Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a Monthly Reconfiguration Auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.15.7 for each Capacity Commitment Period.

III.15.7.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through an Annual Capacity Auction, Monthly Reconfiguration Auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.15.7.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.15.7.1.1. Generating Capacity Resources with Capacity Supply Obligations.

III.15.7.1.1.1. Energy Market Offer Requirements.

(a) A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically

available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:

(i) the sum of the Generating Capacity Resource's Notification Time plus Start-Up Time plus Minimum Run Time plus Minimum Down Time is less than or equal to 72 hours; or

(ii) if the Generating Capacity Resource cannot meet the offer requirements in Section III.15.7.1.1.1(a)(i) due to physical design limits, then the resource shall be offered into the Day-Ahead Energy Market at a MW amount equal to or greater than its Economic Minimum Limit at a price of zero or shall be self-scheduled in the Day-Ahead Energy Market at a MW amount equal to or greater than the resource's Economic Minimum Limit.

(b) Notwithstanding the foregoing, if the Generating Capacity Resource is a Settlement Only Resource, it may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.1.1.2. Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the known capability of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.19.

III.15.7.1.1.3. [Reserved.]

III.15.7.1.1.4. [Reserved.]

III.15.7.1.1.5. Additional Requirements for Generating Capacity Resources.

Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1 and the requirement to provide to the ISO, upon request and as soon as practicable, confirmation of gas volume schedules sufficient to deliver the energy scheduled for each Generating Capacity Resource using natural gas; and

(c) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures (except that Settlement Only Resources are not subject to outage requirements), provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.15.7.1.2. Import Capacity Resources with Capacity Supply Obligations.

III.15.7.1.2.1. Energy Market Offer Requirements.

A Market Participant with an Import Capacity Resource must offer one or more External Transactions to import energy in the Day-Ahead Energy Market and Real-Time Energy Market for every hour of each Operating Day at the same external interface that, in total, equal the resource's Capacity Supply Obligation, except that:

(a) the offer requirement does not apply to any hour in which any External Resource associated with an Import Capacity Resource is on an outage;
(b) the Day-Ahead Energy Market offer requirement does not apply to any hour in which the import transfer capability of the external interface is 0 MW, and;
(c) the Real-Time Energy Market offer requirement does not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which Coordinated Transaction Scheduling is implemented.

Each External Transaction submitted in the Day-Ahead Energy Market must reference the associated Import Capacity Resource.

Each External Transaction submitted in the Real-Time Energy Market in accordance with Section III.1.10.7 must reference the associated Import Capacity Resource.

III.15.7.1.2.2. Additional Requirements for Import Capacity Resources.

A Market Participant with an Import Capacity Resource that is associated with an External Resource must:

(a) comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the External Resource's native Control Area, and;
(b) notify the ISO of all outages impacting the Capacity Supply Obligation of the Import Capacity Resource in accordance with the outage notification requirements in ISO New England Operating Procedure No. 5.

III.15.7.1.3. Intermittent Power Resources with Capacity Supply Obligations.

III.15.7.1.3.1. Energy Market Offer Requirements.

(a) Market Participants with Intermittent Power Resources that are Dispatchable Resources and have a Capacity Supply Obligation are required to submit offers in the Day-Ahead Energy Market consistent with the Market Participant's expectation of the output of the resource in Real-Time. Market Participants with non-dispatchable Intermittent Power Resources with a Capacity Supply Obligation may submit, but are not required to submit, offers into the Day-Ahead Energy Market. Market Participants are required to submit offers for Intermittent Power Resources with a Capacity Supply Obligation for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day-Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

(b) Notwithstanding the foregoing, an Intermittent Power Resource that is a Settlement Only Resource may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.1.3.2. [Reserved.]

III.15.7.1.3.3. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources with Capacity Supply Obligations are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals (except that Intermittent Power Resources that are Settlement Only Resources need not comply with outage requirements).

III.15.7.1.4. [Reserved.]

III.15.7.1.5. Demand Capacity Resources with Capacity Supply Obligations.

III.15.7.1.5.1. Energy Market Offer Requirements.

(a) A Market Participant with an Active Demand Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers for its Demand Response Resources into the Day-Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.15.7.1.5.1; for purposes of the following comparisons, the portion of Demand Reduction Offers not associated with Net Supply shall be increased by average avoided peak transmission and distribution losses. The sum of the Demand Reduction Offers must be equal to or greater than the Active Demand Capacity Resource's Capacity Supply Obligation whenever the Demand Response Resources are physically available. If the Demand Response Resources are physically available at a level less than the Active Demand Capacity Resource's Capacity Supply Obligation, the sum of the Demand Reduction Offers will equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each Demand Reduction Offer from a Demand Response Resource made into the Day-Ahead Energy Market shall also meet the following requirement:

(i) the sum of the Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time plus Minimum Reduction Time plus Minimum Time Between Reductions is less than or equal to 72 hours.

(b) Seasonal Peak Demand Capacity Resources and On-Peak Demand Capacity Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.1.5.2. Requirement that Offers Reflect Accurate Demand Response Resource Operating Characteristics.

For each day, Demand Reduction Offers submitted into the Day-Ahead Energy Market and Real-Time Energy Market for a Demand Response Resource associated with an Active Demand Capacity Resource must reflect the then-known operating characteristics of the resource. Consistent with Section III.1.10.9(d), Demand Response Resources must re-declare to the ISO any changes to offer parameters that occur in real time to reflect the operating characteristics of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.19.

III.15.7.1.5.3. Additional Requirements for Demand Capacity Resources.

(a) A Market Participant may not associate an Asset with a non-commercial Demand Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Demand Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) An Energy Efficiency measure may be added to an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource (other than one consisting of Load Management or Distributed Generation) until two years after the start of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation; provided, however, that a resource that qualified for a Forward Capacity Auction associated with a Capacity Commitment Period beginning on or before June 1, 2024 may install Energy Efficiency measures until May 31, 2027. Once an Energy Efficiency measure has been associated with an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, the measure may not be transferred to a different resource.

(c) For purposes of confirming Capacity Market Commercial Operation as described in Section III.15.2.6, the ISO shall use a summer Seasonal DR Audit value or summer Passive DR Audit value to verify the capacity rating of a Demand Capacity Resource with summer Qualified Capacity. A winter Seasonal DR Audit value or winter Passive DR Audit value may only be used to verify the winter commercial capacity of a Demand Capacity Resource. The summer and winter commercial capacity of a Demand Capacity Resource consisting of Energy Efficiency measures may be verified in any month of the year.

(d) For Active Demand Capacity Resources, a summer Seasonal DR Audit value shall be established for use from April 1 through November 30 and a winter Seasonal DR Audit value shall be established for use from December 1 through March 31. The summer or winter Seasonal DR Audit value of an Active Demand Capacity Resource is equal to the sum of the like-season Seasonal DR Audit values of its constituent Demand Response Resources as determined pursuant to Section III.1.5.1.3.1. The Seasonal DR Audit value of an Active Demand Capacity Resource shall automatically update whenever a new Seasonal DR Audit value is approved for a constituent Demand Response Resource or with changes to the makeup of the constituent Demand Response Resources.

(e) On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources shall in addition: (i) comply with the ISO's measurement and verification requirements pursuant to Section III.15.2.1.1.2.1. and the ISO New England Manuals; and (ii) comply with the auditing and rating requirements as detailed in Sections III.15.7.1.5.4 and III.15.7.1.5.5 and the ISO New England Manuals.

(f) Active Demand Capacity Resources shall in addition: (i) comply with the measurement and verification requirements and the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures; and (ii) comply with the auditing and rating requirements as detailed in Section III.15.7.1.5.5 and the ISO New England Manuals.

III.15.7.1.5.4. On-Peak Demand Capacity Resource and Seasonal Peak Demand Capacity Resource Auditing Requirements.

(a) A summer Passive DR Audit value and a winter Passive DR Audit value must be established for each On-Peak Demand Capacity Resource and Seasonal Peak Demand Capacity Resource in every Capacity Commitment Period during which the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource has an annual or monthly Capacity Supply Obligation.

(b) Summer Passive DR Audit values shall be determined based on data for one or more months of the summer Passive DR Auditing Period (June through August). Winter Passive DR Audit values shall be

determined based on data for one or more months of the winter Passive DR Auditing Period (December through January).

(c) Passive DR Audit values shall be made available to the Market Participant within 20 Business Days following the end of the period for which the audit value is determined by the ISO.

(d) The audit value of an On-Peak Demand Capacity Resource shall be determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the On-Peak Demand Capacity Resource during the Demand Resource On-Peak Hours.

(e) The audit value of a Seasonal Peak Demand Capacity Resource shall be determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the Seasonal Peak Demand Capacity Resource during the Demand Resource Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in a month during the Passive DR Auditing Period, performance during Demand Resource On-Peak Hours in that month may be used.

(f) Passive DR Audit values shall become effective one calendar day after being made available to the Market Participant and remain valid until the earlier of: (i) the next like-season Passive DR Audit value becomes effective or (ii) the end of the following Capability Demonstration Year.

(g) For On-Peak Demand Capacity Resources consisting of Energy Efficiency measures and Seasonal Peak Demand Capacity Resources consisting of Energy Efficiency measures, the ISO shall calculate a summer Passive DR Audit value and a winter Passive DR Audit value in each month of the year. For all other On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources, a Market Participant may request that a summer or winter Passive DR Audit value be determined based on data for, respectively, a summer or winter month outside of the Passive DR Auditing Periods. Such an audit shall not satisfy the Passive DR Audit requirement.

III.15.7.1.5.5. Additional Demand Capacity Resource Audits.

The ISO may perform one or both of the following additional audits for a Demand Capacity Resource to establish or verify the capability of the Demand Capacity Resource and its underlying assets and measures.

(a) Level 1 Audit: the ISO shall establish the audit results by conducting a review of records of the Assets and measures to verify that the reported Assets and measures have been installed and are operational. The audit shall include, but is not limited to, reviewing project or program databases, invoices, installation reports, work orders, and field inspection reports. In addition, the audit may involve reviewing any independent inspections or evaluations conducted as part of program implementation and program evaluation.

(b) Level 2 Audit: the ISO shall establish the audit results by initiating or conducting an on-site field audit to verify the installation and performance of the Assets and measures. Such an audit may include a random or select sample of facilities and measures.

A level 1 audit is not required to precede a level 2 audit. If the results of the audit indicate that the demand reduction capability of the Demand Capacity Resource is less than or greater than its most recent like-season Passive DR Audit value or Seasonal DR Audit value, then the Demand Capacity Resource's audit value shall be adjusted accordingly.

III.15.7.1.6. DNE Dispatchable Generator.

III.15.7.1.6.1. Energy Market Offer Requirements.

DNE Dispatchable Generators with a Capacity Supply Obligation must submit offers into the Day-Ahead Energy Market for the full amount of the resource's expected hourly physical capability as determined by the Market Participant. Market Participants with DNE Dispatchable Generators having a Capacity Supply Obligation must submit offers for the Real-Time Energy Market consistent with the characteristics of the resource. For purposes of calculating Real-Time NCPC Charges, DNE Dispatchable Generators shall have a generation deviation of zero.

III.15.7.1.7. Distributed Energy Capacity Resources with Capacity Supply Obligations.

III.15.7.1.7.1. Energy Market Offer Requirements.

(a) A Market Participant with a Distributed Energy Capacity Resource having a Capacity Supply Obligation shall submit offers for its Distributed Energy Resource Aggregations into the Day-Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.15.7.1.7.1; for purposes of the following comparisons, the portion of any Demand Reductions Offers or Baseline Deviation Offers not associated with Net Supply shall be increased by average avoided peak

transmission and distribution losses. The sum of the offers must be equal to or greater than the Distributed Energy Capacity Resource's Capacity Supply Obligation whenever the Distributed Energy Resource Aggregations are physically available. If the Distributed Energy Resource Aggregations are physically available at a level less than the Distributed Energy Capacity Resource's Capacity Supply Obligation, the sum of the offers must equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each offer from a Distributed Energy Resource Aggregation made into the Day- Ahead Energy Market shall also meet the following requirement:

(i) the sum of the resource's notification time plus start-up time plus Minimum Run Time (or Minimum Deviation Time or Minimum Reduction Time) plus Minimum Down Time (or Minimum Time Between Deviations or Minimum Time Between Reductions) is less than or equal to 72 hours.

(b) Notwithstanding the foregoing, if the Distributed Energy Capacity Resource comprises Settlement Only Distributed Energy Resource Aggregations, it is not obligated to submit Supply Offers into the Day-Ahead Energy Market and may not submit Supply Offers into the Real-Time Energy Market.

III.15.7.1.7.2. Requirement that Offers Reflect Accurate Distributed Energy Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the then-known capability of the resource.

III.15.7.1.7.3. Additional Requirements for Distributed Energy Capacity Resources.

Distributed Energy Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) A Market Participant may not associate an Asset with a non-commercial Distributed Energy Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Distributed Energy Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) Distributed Energy Capacity Resources shall comply with the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

(c) Distributed Energy Capacity Resources shall comply with the auditing and rating requirements as detailed in this Market Rule 1 and the ISO New England Manuals.

(d) For Distributed Energy Capacity Resources, the Seasonal DECR Audit Value shall be established pursuant to Section III.1.7.13.

III.15.7.2. Resources without a Capacity Supply Obligation.

A resource that does not have any Capacity Supply Obligation shall comply with the requirements in this Section III.15.7.2 and shall not be subject to the requirements set forth in Section III.15.7.1 during the Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.15.7.2.1. Generating Capacity Resources without a Capacity Supply Obligation.

III.15.7.2.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. A Generating Capacity Resource that is a Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.2.1.1.1. Day-Ahead Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Day-Ahead Energy Market. If any portion of the offered energy clears in the Day-Ahead Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the operating day,

including the obligation to follow ISO Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.1.1.2. Real-Time Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Real-Time Energy Market. If any portion of the offered energy clears in the Real-Time Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Real-Time Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow ISO Dispatch Instructions. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.1.2. Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation.

Generating Capacity Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with the auditing and rating requirements as detailed in the ISO New England Manuals;

(b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Generating Capacity Resources having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.15.7.2.2. Distributed Energy Capacity Resources without a Capacity Supply Obligation.

III.15.7.2.2.1. Energy Market Offer Requirements.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation is not required to submit offers for the resource into the Day-Ahead Energy Market or Real-Time Energy Market. A Market Participant

with a Settlement Only Distributed Energy Resource Aggregation is not permitted to submit an offer for that resource into the Real-Time Energy Market.

III.15.7.2.2.2. Day-Ahead Energy Market Participation.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation may submit an offer into the Day- Ahead Energy Market. If any portion of the offer clears in the Day-Ahead Energy Market, the entire offer, up to the maximum capability offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market so long as it is not a Settlement Only Distributed Energy Resource Aggregation.

III.15.7.2.2.3. Real-Time Energy Market Participation.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation, that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit an offer in the Real-Time Energy Market so long as the resource is not a Settlement Only Distributed Energy Resource Aggregation, and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.2.4. Additional Requirements for Distributed Energy Capacity Resources Having No Capacity Supply Obligation.

Distributed Energy Capacity Resources without a Capacity Supply Obligation shall comply with the requirements in Section III.15.7.1.7.3.

III.15.7.2.3. Intermittent Power Resources without a Capacity Supply Obligation.

III.15.7.2.3.1. Energy Market Offer Requirements.

An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. An Intermittent Power Resource that is a Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.2.3.2. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals; and

(b) Operating Data collection requirements as detailed in the ISO New England Manuals.

III.15.7.2.4. [Reserved.]

III.15.7.2.5. Demand Capacity Resources without a Capacity Supply Obligation.

III.15.7.2.5.1. Energy Market Offer Requirements.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation is not required to offer Demand Reduction Offers for the Demand Response Resource into the Day-Ahead Energy Market or Real-Time Energy Market.

Seasonal Peak Demand Capacity Resources and On-Peak Demand Capacity Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.2.5.1.1. Day-Ahead Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation may submit a Demand Reduction Offer into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer, up to the Maximum Reduction offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.5.1.2. Real-Time Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit a Demand Reduction Offer in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.5.2. Additional Requirements for Demand Capacity Resources Having No Capacity Supply Obligation.

Demand Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with Section III.15.7.1.5.3(a) and (b) and with the auditing and rating requirements described in Section III.15.7.1.5.5 and the ISO New England Manuals;

(b) for Active Demand Capacity Resources, complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) for Active Demand Capacity Resources, complying with outage requirements as detailed in the ISO New England Operating Procedures and ISO New England Manuals. Active Demand Capacity Resources having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.15.7.3. Exporting Resources.

A resource that is exporting capacity not subject to a Capacity Supply Obligation to an external Control Area shall comply with this Section III.15.7.3 and the ISO New England Manuals. Intermittent Power Resources and Demand Capacity Resources are not permitted to back a capacity export to an external Control Area. The portion of a resource without a Capacity Supply Obligation that will be used in Real-Time to support an External Transaction sale must comply with the energy market offer requirements of Section III.1.10.7 and Section III.1.10.7.A, as applicable.

III.15.7.4. ISO Requests for Energy.

The ISO may request that an Active Demand Capacity Resource, a Generating Capacity Resource, or a Distributed Energy Capacity Resource having capacity that is not subject to a Capacity Supply Obligation provide energy for reliability purposes in the Real-Time Energy Market, but such resource shall not be obligated under this Section III.15 by such a request to provide energy from that capacity. If such resource does provide energy from that capacity, the resource shall be paid based on its most recent offer and is eligible for NCPC.

III.15.7.4.1. Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.15.7.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.

III.15.8. Capacity Payments and Charges.

Revenue in the Annual Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.15.8.1 and Capacity Performance Payments as described in Section III.15.8.2, adjusted as described in Section III.15.8.3 and Section III.15.8.4. Market Participants with a Capacity Load Obligation shall be subject to charges as described in Section III.15.8.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.15 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.15.8.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.15.8.1.1.

III.15.8.1.1. Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in an Annual Capacity Auction, except for the portion of resources designated as Self-Supplied Capacity Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.15.8.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(a) **Annual Capacity Auction**. For a resource whose offer has cleared in an Annual Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the

Forward Capacity Auction in which the offer cleared, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only, and subject to the limitations set forth in Section III.15.2.1.3.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in a Monthly Reconfiguration Auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and the price associated with the Capacity Supply Obligation Bilateral.

III.15.8.1.2 Export Capacity

If there are any unobligated Export Offer Segments from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Annual Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows.

Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x [Cleared MWs of Export Offer Segment]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x [Cleared MWs of Export Offer Segment]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.15.8.5.2.

III.15.8.2. Capacity Performance Payments.

III.15.8.2.1. Definition of Capacity Scarcity Condition.

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

III.15.8.2.2. Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.15.8.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided

for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures, the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.15.8.2.2(c), for any On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.15.8.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(ii) A Demand Response Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource's Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource's Actual Capacity Provided shall not be less than zero.

(iii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

(e) A Distributed Energy Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Metered Quantity for Settlement and Reserve Quantity for Settlement of all the components of its constituent Distributed Energy Resource Aggregations; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Based on the Real-Time operational coordination, the resource must follow any distribution system limitation and update its physical parameters accordingly. The Actual Capacity Provided cannot be less than zero.

(i) The Real-Time demand reduction of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource or Demand Response Distributed Energy Resource Aggregation does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response

Baseline of the Demand Response Asset or Distributed Energy Resource associated with the Demand Response Distributed Energy Resource Aggregation; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.15.8.2.3. Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

provided, however, that the Capacity Balancing Ratio shall not exceed a value of 1.0.

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.15.8.2.A.2 in the New England Control Area during the interval.

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.15.8.2.A.2 in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.15.8.2.A.2 in the Capacity Zone during the interval.

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.15.8.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

III.15.8.2.4. Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Capacity Resource or a Seasonal Peak Demand Capacity Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.15.8.2.5. Capacity Performance Payment Rate.

The Capacity Performance Payment Rate shall be $3500/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.15.8.2.6. Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.15.8.2.A System-Backed Export Charges.

III.15.8.2.A.1 System-Backed Exports.

A System-Backed Export is an External Transaction submitted in accordance with Section III.1.10.7 or Section III.1.10.7.A to export internal energy out of the New England Control Area by a Market Participant in the Real-Time Energy Market: (1) that is not associated with a generator; or (2) for External Transactions associated with a generator, for which the megawatt amount of the External Transaction sale(s) associated with the generator is greater than the sum of the resource's energy output plus the resource's Reserve Quantity For Settlement.

III.15.8.2.A.2 Calculation of System-Backed Export Charges.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a System-Backed Export Charge: (1) for External Transactions associated with a generator, for each resource that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval; and (2) for External Transactions not associated with a generator, for each Market Participant that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval. For each five-minute interval, the System-Backed Export Charge shall be equal to the net System-Backed Export value, calculated in accordance with the formulas set forth below, multiplied by the Capacity Performance Payment Rate, as defined in Section III.15.8.2.5.

For External Transactions associated with a generator,

net System-Backed Export value = the lesser of (the energy output of the generator in the interval + the Reserve Quantity for Settlement of the generator in the interval – the hourly integrated delivered MW for the External Transaction sale(s) associated with the generator) or 0

System-Backed Export Charge = net System-Backed Export value × Capacity Performance Payment Rate

For External Transactions not associated with a generator,

net System-Backed Export value = the lesser of (the hourly integrated delivered MW for the External Transaction purchase(s) of the Market Participant – the hourly integrated delivered MW for the External Transaction sale(s) of the Market Participant) or 0

System-Backed Export Charge = net System-Backed Export value × Capacity Performance Payment Rate

Unless otherwise expressly stated, a System-Backed Export Charge shall not be treated as a Capacity Performance Payment under the Tariff.

III.15.8.3. Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.15.8.3.1 and Section III.15.8.3.2 below.

III.15.8.3.1. Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month shall be limited to an amount equal to the product of the applicable Capacity Auction Offer Price Cap multiplied by the resource's Capacity Supply Obligation for the Obligation Month.

III.15.8.3.2. Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [3 months x (ACAcp – ACAsp) – (12 months x ACAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

ACAcp = the Capacity Clearing Price for the relevant Annual Capacity Auction.

ACAsp = the Annual Capacity Auction Offer Price Cap for the relevant Annual Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.15.8.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month shall be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.15.8.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.15.8.3.2(b).

III.15.8.4. Allocation of Deficient or Excess Capacity Performance Payments and System-Backed Export Charges.

For Capacity Scarcity Conditions as described in Section III.15.8.2.1, the ISO shall allocate deficient or excess Capacity Performance Payments and System-Backed Export Charges as described in subsections (a), (b), and (c) below.

(a) If the sum of all Capacity Performance Payments and System-Backed Export Charges to all resources subject to a Capacity Scarcity Condition in an Obligation Month is positive, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.15.8.3, the deficiency shall be charged to resources in proportion to the sum of each such resource's positive Capacity Performance Score for the Obligation Month.

(b) If the sum of all Capacity Performance Payments and System-Backed Export Charges to all resources subject to a Capacity Scarcity Condition in an Obligation Month is negative, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.15.8.3, the excess shall be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.15.8.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.15.8.3, and the remaining excess shall be further allocated to other resources in the same manner as described in this Section III.15.8.4(b).

(c) If a deficiency of Capacity Performance Payments exists due to one or more resources reaching the stop-loss limit described in Section III.15.8.3, the deficiency shall be charged to all resources subject to a Capacity Scarcity Condition in an Obligation Month that have not reached their stop-loss limit (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. If the charge described in Section III.15.8.4(a) or the charge described in this Section III.15.8.4(c) causes a resource to reach the stop-loss limit described in Section III.15.8.3, then the stop-loss limit described in Section III.15.8.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.15.8.4(c).

III.15.8.5. Charges to Market Participants with Capacity Load Obligations.

III.15.8.5.1. Calculation of Capacity Charges.

For purposes of this Section III.15.8.5.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in rate component (b) of Sections III.15.8.5.1.1 through III.15.8.5.1.8 shall be divided by the number of days in the month to derive a daily settlement value.

III.15.8.5.1.1. Annual Capacity Auction Charge.

The ACA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone ACA Costs divided by Zonal Capacity Obligation.

Where:

Capacity Zone ACA Costs, for each Capacity Zone, are the Total ACA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total ACA Costs are the sum of, for all Capacity Zones, Capacity Supply Obligations in each zone (the total obligation awarded to resources in the Annual Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.15.8.5.1.5) multiplied by the applicable clearing price from the auction in which the obligation was awarded to the resource.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.15.8.5.1.2. Monthly Reconfiguration Auction Charge.

The monthly reconfiguration auction charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total Monthly Reconfiguration Auction Costs divided by Total Zonal Capacity Obligation.

Where:

Total Monthly Reconfiguration Auction Costs are the sum of, for all Capacity Zones, the product of Capacity Supply Obligations acquired through the Monthly Reconfiguration Auction in each zone and the applicable Monthly Reconfiguration Auction clearing price, minus the sum of, for all Capacity Zones, any Capacity Supply Obligations shed through the Monthly Reconfiguration Auction in each zone and the applicable Monthly Reconfiguration Auction clearing price.

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.15.8.5.1.3. HQICC Capacity Charge.

The HQICC capacity charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total HQICC Credits divided by Total Capacity Load Obligation.

Where:

Total HQICC credits are the product of HQICCs multiplied by the sum of the values calculated in Sections III.15.8.5.1.1(b), III.15.8.5.1.2(b), III.15.8.5.1.5(b), III.15.8.5.1.6(b), III.15.8.5.1.7(b), and III.15.8.5.1.8(b) in the Capacity Zone in which the HQ Phase I/II external node is located.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.15.8.5.1.4. Self-Supply Adjustment.

The self-supply adjustment is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) the Self-Supply Variance divided by Total Capacity Load Obligation.

Where:

Self-Supply Variance is the difference between foregone capacity payments and avoided capacity charges associated with designated self-supply quantities.

Foregone capacity payments to Self-Supplied Capacity Resources are the sum, for all Capacity Zones, of the product of the zonal Capacity Supply Obligation designated as self-supply, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Avoided capacity charges are the sum, for all Capacity Zones, of the product of any designated self-supply quantities multiplied by the sum of the values calculated in Sections III.15.8.5.1.1.(b), III.15.8.5.1.2(b), III.15.8.5.1.5(b), III.15.8.5.1.6(b), III.15.8.5.1.7(b) and III.15.8.5.1.8(b) in the Capacity Zone associated with the designated self-supply quantity.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.15.8.5.1.5. Intermittent Power Resource Capacity Adjustment.

The Intermittent Power Resource capacity adjustment in a winter season for the Obligation Months from October through May is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) the Intermittent Power Resource Seasonal Variance divided by Total Zonal Capacity Obligation.

Where:

Intermittent Power Resource Seasonal Variance is the difference between the ACA payments for Intermittent Power Resources in the Obligation Month and the base ACA payments for Intermittent Power Resources.

ACA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to Intermittent Power Resources in the Annual Capacity Auction process for the Obligation Month pursuant to Section III.15.4.2.3, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Base ACA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Annual Qualified Capacity procured from Intermittent Power Resources in the Annual Capacity Auction process, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Total Zonal Capacity Obligation is the total Zonal Capacity Obligation in all Capacity Zones.

III.15.8.5.1.6. CTR Transmission Upgrade Charge.

The CTR transmission upgrade charge is: (a) the Capacity Load Obligation in the Capacity Zones to which the applicable interface limits the transfer of capacity, multiplied by (b) Zonal CTR Transmission Upgrade Cost divided by Zonal Capacity Obligation.

Where:

Zonal CTR Transmission Upgrade Cost for each Capacity Zone to which the interface limits the transfer of capacity is the amount calculated pursuant to Section III.15.8.5.4.1(f), multiplied by the Zonal Capacity Obligation and divided by the sum of the Zonal Capacity Obligation for all Capacity Zones to which the interface limits the transfer of capacity.

III.15.8.5.1.7. CTR Pool-Planned Unit Charge.

The CTR Pool-Planned Unit charge is: (a) the total Capacity Load Obligation in all Capacity Zones less the amount of any CTRs specifically allocated pursuant to Section III.15.8.5.4.2, multiplied by (b) CTR Pool-Planned Unit Cost divided by Total Zonal Capacity Obligation less the amount of any CTRs specifically allocated pursuant to Section III.15.8.5.4.2.

Where:

The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.15.8.5.4.2(b).

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.15.8.5.1.8. Multi-Year Rate Election Adjustment.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where:

Zonal Multi-Year Rate Election Costs is the sum, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that were terminated pursuant to Section III.13.3.4A or Section III.15.A.2.1, or withdrawn pursuant to Section III.15.A.2.3), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, multiplied by the Zonal Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation and divided by the Total Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning prior to June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where:

> Zonal Multi-Year Rate Election Costs is the sum in each Capacity Zone, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that were terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period.

III.15.8.5.2. Calculation of Capacity Load Obligation and Zonal Capacity Obligation.

The ISO shall assign each Market Participant a share of the Zonal Capacity Obligation prior to the commencement of each Obligation Month for each Capacity Zone established in the Annual Capacity Auction pursuant to Section III.12.4. The Zonal Capacity Obligation of a Capacity Zone that contains a nested Capacity Zone shall exclude the Zonal Capacity Obligation of the nested Capacity Zone.

The Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year one year prior to the start of the Capacity Commitment Period to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year one year prior to the start of the Capacity Commitment Period.

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with the receipt of electricity from the grid by Storage DARDs for later injection of electricity back to the grid; when all load of a Distributed Energy Resource Aggregation participating as a Storage DARD is load associated with the receipt of electricity from the grid for later injection of electricity back to the grid; Station service load that is modeled as a discrete Load Asset and

the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as a discrete Load Asset and is exclusively related to an Alternative Technology Regulation Resource following AGC Dispatch Instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A Market Participant's share of Zonal Capacity Obligation for each day of the month and each Capacity Zone shall equal the product of: (i) the Capacity Zone's Zonal Capacity Obligation as calculated above and (ii) the ratio of the sum of the load serving entity's daily Coincident Peak Contributions, to the sum of all load serving entities' daily Coincident Peak Contributions in that Capacity Zone.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each day of the month and each Capacity Zone, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied Capacity Resource designations. A Capacity Load Obligation can be a positive or negative value.

A Market Participant's share of Zonal Capacity Obligation will not be reconstituted to include the demand reduction of a Demand Capacity Resource, Demand Response Resource, or a Demand Response Distributed Energy Resource Aggregation.

III.15.8.5.2.1. Charges Associated with Dispatchable Asset Related Demands.

Dispatchable Asset Related Demand resources will not receive Annual Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.15.8.5.3. Excess Revenues.

Any payment associated with a Capacity Supply Obligation Bilateral that was to accrue to a Capacity Acquiring Resource for a Capacity Supply Obligation that is terminated pursuant to Section III.13.3.4A or

Section III.15.A.2.1, or withdrawn pursuant to Section III.15.A.2.3, shall instead be allocated to Market Participants based on their pro rata share of all Capacity Load Obligations in the Capacity Zone in which the terminated resource is located.

III.15.8.5.4. Capacity Transfer Rights.

III.15.8.5.4.1. Specifically Allocated CTRs Associated with Transmission Upgrades.

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.15.8.5.1.6.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.15.8.5.1.6.

(e) **Maine Export Interface**. Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine export interface for as long as Casco Bay continues to pay to support the transmission upgrades.

(f) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price in the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price in the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. This value will be divided by the number of days in the month to derive a daily settlement value.

III.15.8.5.4.2. Specifically Allocated CTRs for Pool-Planned Units.

(a) In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive for each Capacity Commitment Period an allocation of CTRs for each such unit that is the product of: (i) the MW quantity of capacity that the unit cleared in the Annual Capacity Auction associated with the Capacity Commitment Period; and (ii) the municipal utility's ownership entitlements in such unit. The CTRs allocated pursuant to this Section may be designated as self-supply quantities as described in Section III.15.2.9. Municipal utility ownership entitlements are set as shown in the table below and are not transferrable.

	Millstone 3	Seabrook	Stonybrook GT 1A	Stonybrook GT 1B	Stonybrook GT 1C	Stonybrook 2A	Stonybrook 2B	Wyman 4
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%

Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%
Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%
Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%

Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%

Allocation of CTRs as described in this Section shall expire on December 31, 2040. If a unit listed in the table above retires prior to December 31, 2040, however, allocation of CTRs for such unit shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Annual Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant (collectively, "WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

(b) For any CTRs specifically allocated pursuant to this Section that are not designated self-supply quantities for the Capacity Commitment Period, the municipal utility entitlement holder shall receive a credit reflecting the value of such remaining CTRs. The value of each remaining CTR shall be calculated as the product of: (i) the Capacity Clearing Price for the Capacity Zone where the load of the municipal utility entitlement holder is located minus the Capacity Clearing Price for the Capacity Zone in which the Pool-Planned Unit is located; and (ii) the remaining MW quantity. This value will be divided by the number of days in the month to derive a daily settlement value.

III.15.8.5.5. Annual Capacity Market Net Charge Amount.

The Annual Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charges; (b) its revenues from any applicable specifically allocated CTRs; and (c) any applicable export charges.

III.15.9. Information Publication and Reporting.

III.15.9.1. Publication of Certain Data Prior to the Annual Capacity Auction.

For each Annual Capacity Auction, no later than one Business Day before the opening of the Annual Capacity Auction Offer Window, the ISO shall publish publicly on its website:

a. which Capacity Zones shall be modeled in the Annual Capacity Auction;
b. the transmission interface limits as determined pursuant to Section III.12.5;
c. which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Annual Capacity Auction;
d. determinations on which new resources have been rejected due to deliverability impacts pursuant to Section III.15.2.3;
e. the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Annual Capacity Auction, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone;
f. for each resource that submitted a Load-Side Relationship Certification, the following information: the resource technology type; which qualifying circumstance in Section III.A.21.1.4 was asserted in the Load-Side Relationship Certification; the relevant state policy asserted in the Load-Side Relationship Certification, if any; whether the ISO accepted or rejected the Load-Side Relationship Certification; and, consequently, whether the resource was subject to a review for the exercise of buyer-side market power; and
g. which resources are qualified to participate in the Annual Capacity Auction, including resource type, Capacity Zone, and Annual Qualified Capacity.

III.15.9.2. Publication of Certain Data After Conducting the Annual Capacity Auction

In addition to the Annual Capacity Auction results information identified by Section III.15.2.11 and Section III.15.4.3 of Market Rule 1, within 15 days of conducting the Annual Capacity Auction, the ISO shall publish publicly on its website:

a. which Capacity Offers, satisfying the requirements of Section III.A.21.1 of Market Rule 1, were not reviewed for an exercise of buyer-side market power because of one of the conditions described in Sections III.A.21.1.1, III.A.21.1.2, or III.A.21.1.4 of Market Rule 1; and the condition met by each such resource;
b. the Internal Market Monitor's determinations made as part of any buyer-side market power review conducted pursuant to Section III.A.21.2 and any Capacity Offer Floor Price determinations made pursuant to Section III.A.21.3 with regard to capacity not previously cleared

in an Annual Capacity Auction or Forward Capacity Auction, and the basis for any such determinations; except that offer price information and any information employed by the Internal Market Monitor in making these determinations related to the potential impact of a Capacity Resource's offer on Capacity Clearing Prices shall not be published publicly;

c. the Internal Market Monitor's determinations regarding Proposed Capacity Offers, including whether the Internal Market Monitor accepted or rejected prices specified in a resource's Proposed Capacity Offer that were subject to Internal Market Monitor review and whether the Internal Market Monitor accepted or rejected the cost components of the resource' offer, which are set forth in Section III.A.22.2.3(a). No offer prices, cost components, or other underlying data shall be published; and,

d. which resources offering capacity not previously offered into an Annual Capacity Auction or Forward Capacity Auction were qualified to participate in the Annual Capacity Auction (this information will include a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations).

New England Governors, State Utility Regulators and Related Agencies

Connecticut
The Honorable Ned Lamont
Office of the Governor
State Capitol
210 Capitol Avenue
Hartford, CT 06106
natalie.braswell@ct.gov

Connecticut Attorney General's Office
165 Capitol Avenue
Hartford, CT 06106
john.wright@ct.gov
robert.marconi@ct.gov

Connecticut Department of Energy and Environmental Protection
79 Elm Street
Hartford, CT 06106
eric.annes@ct.gov

Connecticut Public Utilities Regulatory Authority
10 Franklin Square
New Britain, CT 06051-2605
seth.hollander@ct.gov
scott.muska@ct.gov

Maine
The Honorable Janet Mills
One State House Station
Office of the Governor
Augusta, ME 04333-0001
jeremy.kennedy@maine.gov
scott.ogden@maine.gov
jerry.reid@maine.gov
dan.burgess@maine.gov

Maine Department of Energy Resources
62 State House Station
Augusta, ME 04333
celina.cunningham@maine.gov

Maine Public Utilities Commission
18 State House Station
Augusta, ME 04333-0018
maine.puc@maine.gov
amy.g.dumeny@maine.gov

Massachusetts
The Honorable Maura Healey
Office of the Governor
State House
Boston, MA 02133
rebecca.l.tepper@mass.gov
Mary.L.Nuara@mass.gov
Austin.W.Dawson@mass.gov

Massachusetts Attorney General's Office
One Ashburton Place
Boston, MA 02108
elizabeth.a.anderson@mass.gov
matthew.saunders@mass.gov
Allison.OConnell@mass.gov

Massachusetts Department of Energy Resources
100 Cambridge Street, Suite 1020
Boston, MA 02114
ben.dobbs@state.ma.us

Massachusetts Department of Public Utilities
One South Station
Boston, MA 02110
morgane.treanton@state.ma.us
william.j.anderson2@mass.gov
Liz.Anderson2@mass.gov
Greggory.Wade@mass.gov
dpu.electricsupply@mass.gov

New Hampshire
The Honorable Kelly Ayotte
Office of the Governor
26 Capital Street
Concord, NH 03301

New Hampshire Department of Energy
21 South Fruit Street, Ste 10
Concord, NH 03301
jared.s.chicoine@energy.nh.gov
amanda.o.noonan@energy.nh.gov
joshua.w.elliott@energy.nh.gov
david.j.shulock@energy.nh.gov

New England Governors, State Utility Regulators and Related Agencies

New Hampshire Public Utilities Commission
21 South Fruit Street, Ste. 10
Concord, NH 03301-2429
regionalenergy@puc.nh.gov
mark.w.dellorfano@puc.nh.gov
pradip.k.chattopadh1@puc.nh.gov
christopher.j.ellmsjr@puc.nh.gov

Rhode Island
The Honorable Daniel McKee
Office of the Governor
82 Smith Street
Providence, RI 02903
rosemary.powers@governor.ri.gov

Rhode Island Office of Energy Resources
One Capitol Hill
Providence, RI 02908
christopher.kearns@energy.ri.gov

Rhode Island Public Utilities Commission
89 Jefferson Blvd.
Warwick, RI 02888
ronald.gerwatowski@puc.ri.gov
todd.bianco@puc.ri.gov

Vermont
The Honorable Phil Scott
Office of the Governor
109 State Street, Pavilion
Montpelier, VT 05609
jason.gibbs@vermont.gov

Vermont Public Utility Commission
112 State Street
Montpelier, VT 05620-2701
Ed.mcnamara@vermont.gov
margaret.cheney@vermont.gov

Vermont Department of Public Service
112 State Street, Drawer 20
Montpelier, VT 05620-2601
bill.jordan@vermont.gov
kerrick.johnson@vermont.gov

Related New England Agencies
Heather Hunt, Executive Director
New England States Committee on Electricity
424 Main Street
Osterville, MA 02655
heatherhunt@nescoe.com
jeffbentz@nescoe.com
shannonbeale@nescoe.com
sheilakeane@nescoe.com
nathan.forster@nescoe.com

George Twigg, Executive Director
New England Conference of Public Utilities Commissioners
PO Box 9111
Essex, VT 05451
gtwigg@necpuc.org

Philip L. Bartlett, II, President
New England Conference of Public Utilities Commissioners
18 State House Station
Augusta, ME 04333-0018
phil.bartlett@maine.gov