July 16, 2026

<u>**BY ELECTRONIC FILING**</u>

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 Adjust Parameters for the Day-Ahead Ancillary Services Market, Docket No. ER26-___-000

<u>REQUEST FOR ORDER ON OR BEFORE SEPTEMBER 14, 2026</u>

Dear Secretary Reese:

Pursuant to Section 205 of the Federal Power Act ("Section 205"),[1] ISO New England Inc. ("ISO" or "ISO-NE"), joined by the New England Power Pool ("NEPOOL") Participants Committee (together, "Filing Parties"),[2] hereby submit to the Federal Energy Regulatory Commission (the "Commission") this transmittal letter ("Filing Letter") and revisions to the ISO Transmission, Markets, and Services Tariff ("Tariff")[3] to make certain post-implementation adjustments ("Proposed Adjustments") to the jointly-optimized Day-Ahead Ancillary Services

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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, which pursuant to the Participants Agreement provides the sole Participant Processes for advisory voting on ISO matters, supported the changes reflected in this filing and, accordingly, joins in this Section 205 filing. Although NEPOOL fully supports the changes filed herein, it does not have an institutional view or position on the rationale offered, including those offered in Sections I, III, and IV 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 defined in this transmittal are intended to have the meaning given to such terms in the Tariff.

("DA A/S") Market and Day-Ahead Energy Market (together, "Day-Ahead Market"), which went live just over a year ago on March 1, 2025, by order of the Commission.[4]

I. OVERVIEW

The Proposed Adjustments, which could be implemented beginning October 22, 2026 (for the clearing of the Day-Ahead Market for the October 23, 2026 Operating Day), consist of the following:

1. Adjusting the Forecast Energy Requirement Demand Quantity ("FER Demand Quantity"), as specified in revised Tariff Section III.1.8.4, to better reflect the expected contribution of front-of-the-meter ("FtM") wind and solar resources to meeting the Forecasted Energy Requirement ("FER");

2. Setting a floor on the Day-Ahead Ancillary Services Strike Price ("Strike Price"), as specified in revised Tariff Section III.1.8.2, based on the empirically observed marginal costs of energy of combustion turbine resources selling DA A/S;

3. Adjusting the threshold for the Impact Test, as specified in Tariff Section III.A.8.1.2, to have a floor of $3/MWh; and

4. Removing the credit adjustment to the Hourly Revenue calculation of Net Commitment-Period Compensation ("NCPC"), as specified in Tariff Section III.F.2.3.1.3, to prevent Day-Ahead External Transactions that do not have a corresponding Real-Time offer and are ineligible to receive the Forecast Energy Requirement Price ("FER Price") from receiving the equivalent in NCPC.

Currently, the Day-Ahead Market jointly procures and prices Day-Ahead Ancillary Services—ten- and thirty-minute Flexible Response Services ("FRS") and the sixty-minute Energy Imbalance Reserve ("EIR")—as well as physical energy to meet expected Real-Time load through the FER and also satisfy operating reserve requirements.[5] Importantly, the Proposed Adjustments do not alter the basic design or underlying purpose of the DA A/S Market to procure and price sufficient reserves in the Day-Ahead Market to reliably meet the region's next-day operating reserve and load forecast requirements. Rather, the Proposed Adjustments are intended to update key parameters of the DA A/S Market design based upon observed outcomes since its implementation in March 2025, with the goal of making the design more efficient and cost-effective.

The proposals to reduce the FER Demand Quantity to better account for FtM wind and solar resources and to set a floor on the Strike Price are directly responsive to the recommendations of the ISO's Internal Market Monitor ("IMM"), which has been active in observing the operation of the DA A/S Market since its inception and communicating the IMM's

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[4] *ISO New England Inc., Order Accepting Tariff Revisions*, 186 FERC ¶ 61,076 (2024).

[5] Along with physical supply, the EIR contributes to satisfying the load forecast and receives the FER Price.

findings to stakeholders.[6] While also responsive to the expressed concerns of some stakeholders about the unanticipated high costs of the DA A/S Market, the Proposed Adjustments primarily are intended to improve the overall efficiency of the design.

The FER Demand Quantity, which currently is based on the ISO's load forecast, and Strike Price calculation serve as key inputs into the clearing of the jointly-optimized Day-Ahead Market and impact the efficiency of the design. As observed over the last year since inception, the FER constraint in the Day-Ahead Market tends to underestimate the contribution of FtM wind and solar supply as compared to the ISO's Day-Ahead reliability assessment under its Reserve Adequacy Analysis ("RAA"), conducted in the Day-Ahead timeframe after clearing the Day-Ahead Market. This results in a costly market inefficiency, insofar as the Day-Ahead Market may commit additional generation or procure more physical supply than necessary to satisfy the Real-Time load forecast. The Proposed Adjustments therefore include a proposal to adjust downward the FER Demand Quantity to account for this discrepancy, thereby improving the alignment of the FER constraint with the ISO's reliability assessment and reducing this inefficiency and related costs.

Empirical observations further show that a significant share of DA A/S awards have been cleared by combustion turbine ("CT") generators, which are generally (though not exclusively) fueled by distillate oil.[7] To better align the Strike Price with their marginal costs, the Proposed Adjustments introduce a floor based on a short-run marginal cost estimate for an efficient CT generator. Under the proposal, the Strike Price for each hour will be the greater of: (i) the current calculation, which is based on a Gaussian Mixture Model ("GMM") with a $10/MWh baseline adder, and (ii) the floor value derived from the marginal cost estimate, including emissions costs, of an efficient CT generator.[8] The floor is designed to remain below the marginal cost of this set of DA A/S suppliers by using a relatively efficient heat rate (9 MMBtu/MWh) and lowest-cost fuel assumptions. This approach largely preserves performance incentives in high-load, high-stress hours while narrowing the gap between the Strike Price and the cost of physical hedging, thereby reducing risk premiums and encouraging greater participation.

The targeted adjustments to the Impact Test threshold and NCPC credit calculation are based on the ISO's observation of unintended outcomes of the DA A/S Market design. The ISO is proposing a floor price of $3/MWh to be applied to the current threshold for the Impact Test for mitigation, which aligns with a recommendation of the External Market Monitor.[9] This will

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[6] *See* D. Naughton, Executive Director, IMM, ISO-NE*, Memorandum re: Recommended Changes to the Day-Ahead Ancillary Services Market*, to NEPOOL Markets Committee (Feb. 4, 2026) ("IMM Memo"), https://www.iso-ne.com/static-assets/documents/100032/2026_02-imm-memo-with-daas-recommendations.pdf.

[7] Given variability across resources—especially among CTs—the proposal uses conservative assumptions (*i.e*., a 9 MMBtu/MWh heat rate times the lowest-cost fuel index for No. 2 oil, ULS diesel, ULS Kerosene and LS Jet Kerosene) to approximate the short-run marginal costs for a representative CT resource.

[8] Tariff Redline Section III.1.8.2 (a).

[9] *See* Potomac Economics, *2024 Assessment of the ISO-NE Electricity Markets* (recommendation 2024-2), https://www.iso-ne.com/static-assets/documents/100025/iso-ne-2024-emm-report-final.pdf. *See also* IMM's "An Assessment of the Day-Ahead Ancillary Services Market" (June 8, 2026) ("IMM DA A/S Assessment") at 69, https://www.iso-ne.com/static-assets/documents/100036/imm_assessment_of_da_ancillary_services_market.pdf .

prevent the threshold for failing the Impact Test from becoming more stringent (*i.e.*, falling below $3/MWh) in hours when the Day-Ahead Expected Close-Out Component ("Expected Close-Out") increases from $0/MWh (where the Impact Test threshold is $3/MWh) to $2/MWh (the minimum value under the Conduct Test threshold). This adjustment limits the potential for over-mitigation in hours when the Expected Close-Out is very low and market power is not a significant concern.

The Proposed Adjustments also include a minor change to the Day-Ahead Market NCPC rules such that the FER Price is considered (for accounting purposes only) as part of the hourly revenue for Day-Ahead cleared imports regardless of whether there is a corresponding Real-Time transaction. This adjustment is necessary to prevent Day-Ahead imports that are ineligible to receive the FER Price—because they do not have a corresponding Real-Time offer—from effectively receiving that price through a Day-Ahead Market NCPC Credit.

Separately, effective May 1, 2026, the ISO has lowered the discretionary Non-Performance Factor ("NPF") applied to operating reserve requirements from 120% to 115% under ISO New England Operating Procedure No. 8.[10] This change serves to reduce the Day-Ahead Flexible Response Services Demand Quantities[11] procured in the Day-Ahead Market, and also the ten- and thirty-minute operating reserve quantities used in Real-Time system operations. Notably, this recommendation did not require a change to the Tariff. Rather, ISO-NE announced this change to stakeholders in presentations to the NEPOOL Reliability Committee.

In response to both stakeholder requests and an additional IMM recommendation,[12] the ISO also will continue to evaluate ways to improve the performance of the GMM for calculating Strike Prices and Expected Close-Outs. Such improvements do not require a change to the Tariff but only notification to Market Participants of any changes under current Tariff Section III.1.8.2(d).

The Proposed Adjustments are supported by the testimony, sponsored solely by the ISO, of the following: Benjamin Ewing, Technical Manager in Market Development at ISO-NE, whose testimony, attached hereto as Attachment A ("Ewing Testimony"), explains the rationale underlying the proposals to adjust the Strike Price and FER Demand Quantity; and Anna Mazur, an Analyst in Market Development at ISO-NE, whose testimony, attached hereto as Attachment B ("Mazur Testimony"), explains the rationale underlying the proposals to set a $3/MWh floor

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[10] ISO New England Operating Procedure No. 8, Operating Reserve and Regulation, Part III.1.A, provides the ISO discretion in this regard: "In order to meet the NERC Disturbance Control Standard, the ISO Chief Operating Officer (COO) (or designee) may add a nonperformance factor to the Ten-Minute Reserve Requirement based on historic Resource performance."

[11] As defined in the Tariff, these consist of the: 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. Tariff Section I.2.

[12] *See* IMM DA A/S Assessment at 12, 74.

on the threshold for the Impact Test and to adjust the NCPC "Hourly Revenue" calculation for Day-Ahead External Transactions (*i.e.*, imports) without corresponding Real-Time offers.[13]

Using a backcasting methodology, the ISO estimates that the Proposed Adjustments, plus the reduction to the NPF, would have reduced the first year (March 2025 through February 2026) incremental costs of DA A/S as co-optimized in the Day-Ahead Market by $292 million. This represents approximately a 30% reduction, while better aligning the DA A/S design with the ISO's standard reliability assessment, and largely maintaining the incentives provided by the design in hours when they are needed most.[14]

II. 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,[15] 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

[13] The Proposed Adjustments address inefficiencies observed by the IMM after its one-year review of the DA A/S design in the co-optimized Day-Ahead Market and other unintended outcomes. These include updates to key parameters of the design (Strike Price floor, FER DQ adjustment) as well as smaller issues (NCPC credit calculation, Impact Test threshold floor for mitigation) that should improve the overall efficiency of the design. While separate, the Proposed Adjustments are inter-related in the co-optimized Day-Ahead Market—*e.g.*, a resource may offer/clear energy (or EIR) and receive the Day-Ahead LMP and FER Price and/or offer to provide FRS or EIR based on the Strike Price.

[14] Ewing Testimony 24: 9-17. As a disclaimer, these estimates are not predictions of future results and are dependent on assumptions with respect to DA A/S behavior and participation, as described to stakeholders in the presentation titled *Day-Ahead Ancillary Service Post-Implementation Adjustment: Targeted changes to the DA A/S design based on IMM recommendations*, May 12, 2026, NEPOOL Markets Committee, available at https://www.iso-ne.com/static-assets/documents/100035/a06_mc_2026_05_12-14_daas_post_implementation_adjustments_presentation.pdf.

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

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.

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III. STANDARD OF REVIEW

The Tariff Proposed Revisions are submitted pursuant to Section 205 of the Federal Power Act, which "gives a utility the right to file rates and terms for services rendered with its assets."[17] Under Section 205, the Commission "plays 'an essentially passive and reactive' role"[18] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[19] 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

[16] 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.

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

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

[19] *Id*.

rate schedule is more or less reasonable than alternative rate designs."[20] The changes proposed herein "need not be the only reasonable methodology, or even the most accurate."[21] As a result, even if an intervener or the Commission develops an alternative proposal, the Commission must accept the Tariff Revisions if it finds that the changes are just and reasonable.[22]

IV. BACKGROUND

A. Overview of the DA A/S Market

Launched in March 2025, the Day-Ahead Ancillary Services (*i.e*., "DA A/S")[23] Market procures and prices ancillary reserve products needed to meet the region's operating reserve and load forecast requirements, as well as physical energy to satisfy expected Real-Time Load.[24] The market is designed to ensure the system is positioned to reliably meet the ISO's next-day operating plan, while compensating and incentivizing resources to be prepared to perform by delivering energy in real-time if called upon.[25]

The DA A/S design created three new Flexible Response Services (*i.e*., "FRS"): (i) the Day-Ahead Ten Minute Spinning Reserve ("DA TMSR"), (ii) Day-Ahead Ten Minute Non-Spinning Reserve ("DA TMNSR"), and (iii) Day-Ahead Thirty Minute Operating Reserve ("DA TMOR"), as described in Tariff Section III.1.8.3, and the corresponding Day-Ahead Ancillary Services Market Obligations, as defined in Tariff Section III.3.2.1(a)(2).

The DA A/S design also introduced the Energy Imbalance Reserve (*i.e*., "EIR"), which enables the ISO to call on resources to operate above their Day-Ahead schedule within sixty

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[20] *See ISO New England Inc*., 114 FERC ¶ 61,315 at P 33 & n.35 (2005) (*citing Pub. Serv. Co. of New Mexico v. FERC*, 832 F.2d 1201, 1211 (10th Cir. 1987) and *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984) ("*City of Bethany*"), *cert. denied*, 469 U.S. 917 (1984)).

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

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

[23] Terms previously defined above are re-stated to assist the reader in this background section.

[24] Ancillary services are a group of market services that ensure the reliability of the power system. Operating reserves represent additional supply capacity that is available to respond to unexpected contingencies (such as the unexpected loss of a generator or transmission line) during operation of the real-time energy market. Operating reserves are procured both in the Real-Time Energy Market and, with the implementation of the DA A/S market, in the co-optimized Day-Ahead Market. In ISO New England, first and second contingencies represent the largest and second-largest probable single source losses (generators or transmission lines), respectively, the system must withstand while maintaining stability. The system is designed to handle the first contingency within 10 minutes and the second within 30 minutes, ensuring continuous, reliable power. ISO-NE IMM, *An Overview of New England's Wholesale Electricity Markets*: *A Market Primer (2025)* ("IMM Primer"), https://www.iso-ne.com/static-assets/documents/100023/imm-markets-primer.pdf; *see also Day-Ahead Ancillary Service Market and Real-Time Reserve Pricing*, *available at* https://www.iso-ne.com/markets-operations/markets/reserves.

[25] *ISO New England Inc.*, Revisions to ISO New England Transmission, Markets and Services Tariff to Establish a Jointly Optimized Day-Ahead Market for Energy and Ancillary Services of ISO New England Inc., Docket No. ER24-275-000, at 14 (Oct. 31, 2023) ("DASI Filing Letter") ("Broadly, procuring ancillary services Day-Ahead ensures there will be sufficient resources that the region can call on short notice, if needed, to balance energy supply and demand the next day.").

minutes to help bridge the "energy gap" between cleared Day-Ahead physical energy supply and forecasted demand.[26] Both the FRS and EIR are settled through a two-part, financial "call option" tied to Real-Time energy Hub prices.[27]

The DA A/S design further incorporated reliability constraints into the Day-Ahead Market to better align Day-Ahead reserve procurement with Real-Time reliability standards.[28] In particular, the Forecast Energy Requirement (*i.e.*, "FER") constraint ensures that cleared Day-Ahead physical energy supply and EIR meet or exceed the ISO's forecasted load in each hour. Resources contributing to satisfaction of the FER—physical energy supply and EIR—are compensated at the Forecast Energy Requirement Price (*i.e.*, "FER Price").

At its core, the DA A/S construct procures Day-Ahead options on Real-Time energy. Resources that clear DA A/S awards (for any of the four DA A/S products—TMSR, TMNSR, TMOR, and EIR) receive an upfront credit equal to the DA A/S clearing price and incur a close-out charge when the Real-Time Hub LMP exceeds the Strike Price.[29]

The DA A/S construct replaced the prior Forward Reserve Market that operated separately from the energy market and procured only a subset of operating reserves in limited on-peak hours.[30] By comparison, the DA A/S Market provides strong incentives for resources that clear DA A/S awards—*i.e.,* Day-Ahead TMSR, TMNSR, and TMOR and EIR—to cover their Day-Ahead positions when Real-Time Energy prices rise above the Strike Price. Resources must cover their Day-Ahead positions by producing energy or buy out of their awarded positions at potentially higher prices.[31]

The Strike Price is derived from the ISO's in-house Gaussian Mixture Model (*i.e.,* "GMM") and reflects the expected Real-Time Hub Price, plus a $10/MWh base strike adder. The Strike Price is published prior to clearing the Day-Ahead Market.[32]

The GMM also produces a distribution of potential Real-Time LMPs and calculates the Day-Ahead Ancillary Services Expected Close-Out Component (*i.e.,* "Expected Close-Out")

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[26] *See* IMM Primer at Section 5.2.

[27] For every MWh of Day-Ahead A/S awarded, the seller receives a "credit" in the amount of the Day Ahead A/S clearing price and faces a possible "close-out" charge in the amount that the Real-Time Hub Price is higher that the ISO-determined "strike price" for the relevant hour. DASI Filing Letter at 14. "[T]o avoid a loss due to the close-out charge, the resource must be able to respond to higher-than-expected Real-Time energy prices by producing energy in Real-Time and earning Real-Time energy market revenues that offset the close-out charge." DASI Filing Letter at 17.

[28] *See* IMM Primer at Section 5.3 (describing corresponding FRS constraints and FER constraints); *see also* Day-Ahead Ancillary Services Initiative ("DASI"), Project Overview, available at https://www.iso-ne.com/participate/support/participant-readiness-outlook/day-ahead-ancillary-services-initiative.

[29] *See* IMM Primer at Section 3.5.3.

[30] *See id*. at Section 5.1.

[31] DASI Filing Letter at 17 ("In order to avoid a loss due to the close-out charge, the resource must be able to respond to higher-than-expected Real-Time energy prices by producing energy in Real-Time and earning Real-Time energy market revenues that offset the close-out charge.").

[32] Tariff Section III.1.8.2(a).

charges accordingly for each award hour.[33] Expected Close-Out is a key component of competitive DA A/S offers, DA A/S Offer Benchmark Levels,[34] and the thresholds for the Conduct Test[35] and Impact Test[36] for purposes of mitigation.

The ISO has recognized that setting the Strike Price involves an inherent balance between incentives and costs:[37]

- A Strike Price that is "too low" (*i.e*., far lower than the expected marginal costs of producing energy) can serve to inefficiently increase costs.[38]

- A Strike Price that is "too high" (*i.e*., far greater than the expected marginal costs of producing energy) can serve to materially reduce the performance incentives provided by the design.[39]

Achieving the appropriate balance in setting a Strike Price between costs and incentives was a consideration of the initial DA A/S design. For example, the $10/MWh baseline adder reflects

[33] The Expected Close-Out is defined in Section III.A.8.2.1 of Appendix A of Market Rule 1. *See also* DASI Filing Letter at 33.

[34] A resource's Benchmark Level for the hour associated with the resource's DA A/S Offer is defined in Tariff Section III.A.8.2 as "the sum of the Day-Ahead Ancillary Services Expected Close-Out Component and the resource's Day-Ahead Ancillary Services Avoidable Input Cost for such hour."

[35] Under Tariff Section III.A.8.1.1., a DA A/S Offer price fails the conduct test for DA A/S mitigation "in a given hour if such price exceeds an amount greater than the sum of (i) the greater of $2/MWh and 200% of the [Expected Close-Out] as described in Section III.A.8.2.1; and (ii) 150% of the Day-Ahead Ancillary Services Avoidable Input Cost as described in Section III.A.8.2.2."

[36] A DA A/S Offer fails the impact test for DA A/S mitigation under Tariff Section III.A.8.1.2 "if there is an increase in any Day-Ahead Price, as calculated pursuant to Sections III.A.8.3 or III.A.8.4, in any hour of the Operating Day and such increase is greater than 150% of the median difference between: (i) the threshold prices for failing the conduct test described in Section III.A.8.1.1 for all [DA A/S] Offers in the hour of the Operating Day being evaluated; and (ii) the . . . Benchmark Levels as described in Section III.A.8.2 for all [DA A/S] Offers in the hour of the Operating Day being evaluated."

[37] DASI Filing Letter at 20 ("Setting the strike price within the range of expected Real-Time energy prices is complicated by the close-out charge's role in creating incentives to perform for [DA A/S] suppliers.").

[38] DASI Filing Letter at 20, citing Dr. White testimony at 82, 89 ("A way of reducing consumer costs is to raise the strike price by some measure above the expected Real-Time LMP, but to do so in a way that does not blunt the incentives created by setting the strike price near Real-Time LMP in the first place."); *see* IMM Comments on DASI at 8 ("While a higher strike price should result in lower prices for A/S offers, and therefore lower prices and overall costs to consumers, it also should lower the participants' expected amount of a close-out charges, which could dampen the incentives for participation and performance."), citing Dr. White testimony at 89-91.

[39] DASI Filing Letter at 20, citing accompanying Dr. White testimony at 82-87:

> As explained by Dr. White, for the purpose of maximizing incentives, the strike price should reflect Day-Ahead Ancillary Services suppliers' marginal cost of producing energy. Further, for reasons related to the variability of suppliers' marginal costs and the need for a single strike price, the basis for an incentive-maximizing strike price should be the system's overall expected marginal cost of energy in Real-Time.

an effort to reduce Expected Close-Out charges—and ultimately consumer costs—while preserving strong incentives to perform when system conditions warrant.[40]

From the perspective of suppliers, offer prices generally reflect three primary components: (i) potential close-out charges (common to all resources clearing a DA A/S award), (ii) avoidable input costs, including energy-charging (applicable to gas-fired and storage resources), and (iii) a resource-specific risk premium.[41]

The DA A/S design also includes a mitigation framework intended to prevent the exercise of market power through economic and physical withholding. Offers may be mitigated to a competitive "Benchmark Level" if they both: (i) exceed a Conduct Test threshold price, which is 2 times (200% of) the Expected Close-Out costs, or at least $2/MWh, plus 1.5 times (150% of) avoidable input costs, as determined by the ISO (or, to the extent appropriate, an IMM accepted threshold price upon consultation); and (ii) result in Day-Ahead clearing prices that exceed an Impact Test threshold, indicating the ability of a DA A/S offer that fails the Conduct Test threshold to adversely impact Day-Ahead Market prices.[42]

B. Highlights of the IMM's Observations and Recommendations

In February 2026, the IMM issued a memorandum to stakeholders in which it recommended improvements for making the DA A/S design more efficient and cost-effective. The IMM's recommendations were grounded in its "ongoing analysis of DA A/S market outcomes, participant offer behavior, and discussions with market participants."[43]

The IMM stated that "incremental DA A/S costs over the first eleven months" . . . "have exceeded expectations" and "totaled $921 million, representing approximately 9% of the total wholesale energy and ancillary services (E&AS) market, equating to $8.58 MWh of load served."[44] The IMM recognized that "[s]ystem and market conditions have changed in meaningful ways since the IA [*i.e.*, Impact Assessment] study period, . . . including higher load levels, shifts in the supply mix, and higher natural gas prices … [which] have applied upward pressure on both [E&AS] costs." The IMM nonetheless found that "changes in market fundamentals alone do not fully explain the observed level of DA A/S costs."[45] The IMM concluded:

[40] DASI Filing Letter 20-21 (footnote omitted) (The $10 MWh base strike adder was "an adjustment designed specifically to reduce close-out costs — and, ultimately, consumer costs — in a way that does not materially impact the incentives created by the close-out charge during times when performance matters most.").

[41] DASI Filing Letter at 32.

[42] *See* p. 9 nn. 35 & 36 above.

[43] IMM Memo at 1 (The IMM also "recognized the concerns stakeholders have raised regarding DA A/S costs, particularly in the broader context of overall high energy costs.").

[44] *Id*. 1 n.1, 2-3. "By comparison the ISO's Impact Assessment (IA) for the DA A/S design indicated an annual cost of about 140 million, or roughly 3% of the E&AS market, based on 2019-2021 market data." *Id*. at 4 (emphasis omitted).

[45] *Id.* at 4.

> In practice, participation has been lower, and offer prices higher, than assumed in the IA — including relative to IMM Benchmark Levels and estimated risk premium expectations. These differences have resulted in tighter market supply conditions, high cross-product opportunity costs, and ultimately a higher marginal cost of meeting both energy demand and operating reserve requirements.[46]

Based on its empirical observations, the IMM recommended certain DA A/S design changes, as follows.

An upward adjustment to the Strike Price formulation: The IMM observed that CT generators and combined-cycle ("CC") generators typically cleared DA A/S awards, with approximately 64% and 29% of cleared capability, respectively.[47] The IMM further observed that even the CCs often clear DA A/S in higher-cost duct-firing or upper Supply Offer block operating ranges.[48] Based on its observations, the IMM recommended an upward adjustment to the Strike Price to be closer aligned with the short-run marginal costs of a CT generator.[49] The IMM explained how this would strike a balance between reliability and cost-effectiveness:

> From a reliability perspective, there are two important considerations. First, resources whose SRMC [short-run marginal cost] exceeds the Strike Price provide limited incremental reliability value in this range (between Strike Price and SRMC) because operating below SRMC to cover a closeout charge is not profit-maximizing. In other words, there is no incentive for the resource to physically cover its position until the market supply curve reaches its SRMC. Second, CT commitments—as well as their associated SRMC levels—tend to be strongly correlated with periods of elevated system reliability risk. This relationship is likely to persist as the system continues to rely on fast-start, dispatchable resources to manage steep ramps and peak-load conditions. Accordingly, increasing the Strike Price to more closely align with the SRMC of a CT will better reflect system price levels associated with higher reliability risks. This can improve DA A/S cost effectiveness while maintaining strong performance incentives and reliability benefits.[50]

The spread between the Strike Price and higher short-run marginal costs of these resources creates a "performance-incentive gap" that cannot be fully covered by physically performing in Real-Time.[51] As a result, some resources elect not to participate or to reflect the risk in higher-priced DA A/S offers, thereby putting upward pressure on DA A/S clearing prices.

The IMM therefore recommended adding a floor to the Strike Price to more closely align with the short-run marginal costs of these resources empirically observed to be providing the

[46] *Id*. (internal footnote omitted).

[47] *Id*. at 5.

[48] *Id*.

[49] *Id.* at 6.

[50] *Id*. at 6.

[51] *Id*. at 5.

ancillary services, which should reduce the Expected Close-Out costs and related risk premiums in offers, thereby putting downward pressure on offers and clearing prices.

A downward adjustment to the FER Demand Quantity: the IMM also recommended implementing a downward adjustment to the FER Demand Quantity to better reflect the expected contribution of FtM renewable resources to satisfying the reliability needs.[52] The IMM recommended "reducing the FER demand quantity by the difference between expected Real-Time production and cleared Day-Ahead energy awards of FtM renewables."[53] The IMM opined that lowering the FER Demand Quantity to more accurately reflect FtM wind and solar generation should put downward pressure on the FER Price without sacrificing reliability.

A review and potential downward adjustment to the non-performance factor (*i.e*., NPF): The IMM also recommended that the ISO re-assess the current NPF (last reduced from 125% to 120% in October 2015) included in the ten- and thirty-minute operating reserve requirements "using a data-driven analytical approach." According to the IMM, " a re[-]evaluation may indicate that the existing [1]20% factor is higher than necessary relative to current—and improving—performance outcomes, and that a downward adjustment could better align reserve requirements with demonstrated system needs without compromising reliability."[54]

Notably, this recommendation did not require a change to the Tariff.[55] Rather, ISO-NE presented this issue to stakeholders in presentations to the NEPOOL Reliability Committee Effective May 1, 2026, ISO-NE reduced the reserve NPF from 120% to 115%, based on its own evaluation and consistent with the IMM's recommendation.

In short, the IMM's recommendations were "aimed at the cost pressures associated with offer price and participation levels, while maintaining consistency with the core design objectives."[56]

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[52] *Id*. at 7. For the purposes of this IMM recommendation, FtM renewable resources are utility-scale assets (solar and wind farms) that feed electricity directly into the high-voltage grid, selling to the wholesale markets. Behind-the-meter ("BtM") renewables are customer-sited, smaller systems (rooftop solar, batteries) that power on-site loads first, with excess power sent to the grid.

[53] IMM Memo at 8 ("In practice, the adjustment primarily affects wind and solar resources that clear only a fraction of their expected real-time production in the day-ahead market.").

[54] *Id*. at 10.

[55] ISO New England Operating Procedure No. 8, Operating Reserve and Regulation, Part III.1.A, provides the ISO discretion in this regard: "In order to meet the NERC Disturbance Control Standard, the ISO Chief Operating Officer (COO) (or designee) may add a nonperformance factor to the Ten-Minute Reserve Requirement based on historic Resource performance."

[56] IMM Memo 4-5. The IMM further noted that it would be "issuing future reports on the competitiveness and performance of the DA A/S and may include further recommendations," which "includes a full one-year look-back report planned for May 2026." *Id*. n. 2.

V. PROPOSED TARIFF ADJUSTMENTS

A. The Proposed Adjustment to the FER to Account for Expected FtM Wind and Solar Supply

The Proposed Adjustments include a downward adjustment to the FER Demand Quantity that serves as an input to the Day-Ahead Market in order to more accurately reflect the expected reliability contribution of FtM wind and solar generators in the Real-Time Energy Market that are not fully accounted for in the Day-Ahead Market.

The Day-Ahead Market's FER constraint is intended to ensure sufficient supply capability to satisfy the ISO's load forecast for each hour of the next Operating Day, reflecting this reliability need through a market construct. Both Day-Ahead energy awards to physical suppliers, and EIR awards serve to help satisfy the FER constraint and are compensated at the FER Price.[57]

Under the current rules, the FER Demand Quantity is equal to the ISO's load forecast for each hour.[58] The load forecast reflects expected next-day energy demand and already fully accounts for the expected energy output of behind-the-meter ("BtM") generation (*e.g.*, rooftop solar) by a reduction in the load forecast accordingly.[59]

FtM wind and solar resources, however, tend not to be fully accounted for in the FER constraint as it is currently applied in the Day-Ahead Market. Historically, these resources clear Day-Ahead energy awards that are significantly below their expected Real-Time output—on average approximately 40% of forecasted supply.[60] As a result, the current implementation of the FER constraint understates the expected contribution of FtM wind and solar to meeting forecast Real-Time load.

In contrast, the ISO's Reserve Adequacy Analysis ("RAA") process, which is a standard reliability evaluation conducted in the Day-Ahead timeframe after clearing the Day-Ahead Market, ensures that the ISO has an operating plan capable of satisfying next-day reliability requirements. In the RAA process, FtM wind and solar tend to be relied upon at output levels consistent with the ISO's resource-specific Real-Time forecasts. In doing so, the RAA process efficiently accounts for the energy that the ISO expects to be produced in Real-Time, and thereby avoids the potential for committing the system beyond what is required to meet reliability objectives.

This mismatch between the FER constraint and the RAA process highlights an inefficiency. Because the FER constraint does not fully reflect expected FtM renewable output,

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[57] Ewing Testimony 7: 5-10.

[58] Tariff Section III.1.8.4; Ewing Testimony 7:16

[59] For its "Load Estimate," the ISO posts each day on the internet the total hourly loads scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day. Tariff Section III.1.10.1A (h).

[60] *See* Ewing Testimony 8: 6-12.

the Day-Ahead Market may commit additional resources, or clear additional Day-Ahead energy supply or EIR, to meet the forecasted load. This results in costly over-commitment or over-clearing relative to the reliability need, contrary to the intended purpose of the FER constraint (*i.e.*, to efficiently procure sufficient supply capability to meet the load forecast for each hour of the next Operating Day). The cost associated with such over-commitment or over-clearing, which is not necessary to meet reliability requirements, is ultimately borne by consumers.[61]

To address the potential for the FER constraint to clear more supply than required to satisfy the reliability need, the proposal adjusts the FER Demand Quantity downward to account for expected FtM wind and solar generation that is forecasted to occur in real time but is not expected to clear in the Day-Ahead Market.[62] Specifically, the FER Demand Quantity will equal the load forecast less the positive difference between (i) forecasted FtM wind and solar output and (ii) the amount of such generation expected to clear the Day-Ahead Market (including EIR).[63]

This approach offers several key benefits:

- **Improved efficiency**: It aligns the treatment of FtM wind and solar resources in the FER constraint with their treatment in the ISO's reliability assessments, reducing unnecessary Day-Ahead commitments or over-clearing of Day-Ahead energy or EIR supply.

- **Preserved incentives**: FtM wind and solar resources continue to receive the FER Price for any energy or EIR they clear, with no compensation for uncleared supply.

- **Adaptive design**: If FtM wind and solar resources increase (or decrease) their Day-Ahead participation, the adjustment will naturally shrink (or rise).

- **Consistency**: The proposal better aligns the treatment of FtM and BtM wind and solar resources by ensuring both are reflected in the FER constraint based on expected output.[64]

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[61] *Id*. 9: 18-22, 10: 1-3.

[62] Because the actual amount of FtM wind and solar energy and EIR supply that clears in the Day-Ahead Market is not known until after the market has cleared, the ISO will rely on the initial "case" of the ISO's Day-Ahead Market clearing process, used for unit commitment and determining contingency reserve requirements, as a reliable proxy for forecasting the expected amount of FtM wind and solar energy and EIR supply that will clear in the Day-Ahead Market. *Id*. 10: 8-13.

[63] *See* Tariff Redlines Section III.1.8.4. The proposed FER Demand Quantify shall be the ISO's load forecast "less (2) the greater of (i) the forecast of front-of-the-meter dispatchable wind and solar resources' total real-time energy supply, as adjusted for any expected operating conditions, less the total energy supply and ancillary services from such resources forecast to clear in the Day-Ahead Market and (ii) zero." Ewing Testimony 10: 15-20, 11: 1-3, 13: 10-18.

[64] *Id*. 13: 22-25, 14: 1-9.

The ISO estimates that this adjustment would have reduced the effective load used to calculate the FER Demand Quantity by approximately 422 MW on average for the period of March 2025 – February 2026, with no adjustment occurring in 3% of hours.[65]

In summary, the current FER framework understates the contribution of FtM wind and solar generation relative to the ISO's own reliability assessments, leading to inefficient over-commitment or over-clearing in the Day-Ahead Market relative to the reliability need. The Proposed Adjustment resolves this discrepancy by aligning the FER constraint with the ISO's reliability assessment, thereby reducing inefficiencies and associated costs while maintaining appropriate market incentives. As further explained in the accompanying Ewing Testimony, this Proposed Adjustment to the FER Demand Quantity will not result in increased out-of-market commitments or increased uplift payments.The RAA process—which has been employed by the ISO to produce reliable next-day operating plans for decades—determines whether any additional, out-of-market commitments may be required. Improving the alignment of the FER constraint and the RAA process will not serve to increase reliance on out-of-market commitments or produce associated uplift payments.[66]

Nor will this Proposed Adjustment negatively impact system reliability. The DA A/S Market generally, and applying the FER constraint specifically, are meant to reflect the ISO's reliability needs (*i.e*., those considered by the RAA process) through a market construct. With this proposed change, the DAM will be more closely aligned with the RAA process, which began incorporating the forecasted output of intermittent renewable resources in 2014. Rather than negatively impacting reliability, this proposed change will avoid the potential that is inherent in the current application of the FER constraint for over-committing or over-clearing the system relative to the ISO's reliability need. This overcommitment or over-clearing is both unnecessary and costly for consumers.[67]

Any concerns about capturing "uncertainty" in the FER constraint are also misplaced. Uncertainties naturally exist in both the current and proposed implementations of the FER constraint. However, it is not the purpose of this constraint to reflect both the ISO's expectation and uncertainties around that expectation. The ISO separately procures FRS (*i.e*., the suite of 10- and 30-minute reserve products) in the DAM and designates Operating Reserves in Real-Time for the express purpose of responding quickly to unanticipated events that do not align with the ISO's next-day expectations. This fast-ramping capability is relied upon to respond to unexpected system events of all kinds, including instances when FtM wind and solar output deviates from expectation or loads come in higher than expected. The ISO has discretion to set these requirements based upon system needs, and it could choose to increase these requirements if necessary to account for such uncertainty. In addition, the ISO discussed with stakeholders a future workplan item dedicated to evaluating uncertainty-related constraints and products in its

[65] *Id*. 14: 11-14.

[66] *Id*. 11: 6-10, 14: 17-22. As adjusted the FER Demand Quantity will continue to serve as an input to clearing the Day-Ahead Market.

[67] *Id.* 11: 13-22, 12: 1-2.

energy and ancillary services markets, which may more directly handle uncertainty around items such as the load forecast and wind and solar output.[68]

B. The Proposed Adjustment to Add a Floor to the Strike Price Calculation

Currently, the Strike Price for each hour is set at the expected next-day Real-Time Hub Locational Marginal Price ("LMP") plus a $10/MWh baseline adder.[69] In many cases, however, this calculation falls well below the short-run marginal costs of the resources that have cleared DA A/S.[70] Empirical observations show that DA A/S awards have been cleared primarily by CT generators and, to a lesser extent, CC generators.[71] These CTs typically run on higher-cost distillate fuels (No. 2 Oil, Ultra-Low Sulfur Kerosene, Ultra-Low Sulfur Diesel, and Low Sulfur Jet Kerosene), while CCs typically run on natural gas.[72]

As a result, resources may require higher risk premiums or opt out of the DA A/S market due to the costs of physically hedging in Real-Time (*i.e.*, the gap between the Strike Price and their short-run marginal costs). The IMM has observed that this dynamic may contribute to lower participation and higher offer prices.[73]

As discussed throughout the stakeholder process,[74] the call option settlement design provides efficient performance incentives when the Strike Price is at or below a resource's marginal cost of energy supply.[75] When the Strike Price is set too low, it provides limited incremental reliability value, as resources are not economically incentivized to physically cover

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[68] *Id*. 12: 5-23, 13: 1-7. *See* ISO-NE Memorandum to NEPOOL Markets Committee dated March 4, 2026, https://www.iso-ne.com/static-assets/documents/100033/a06_mc_2026_3_10-12_dynamic_operating_reserves_memo.pdf.

[69] *Id*. 15: 1-3. Tariff Section III.1.8.2(a) currently states: "For each hour of the Operating Day, the ISO shall specify the Day-Ahead Ancillary Services Strike Price in $/MWh. The value of the Day-Ahead Ancillary Services Strike Price represents an amount that is the greater of (i) $10/MWh greater than a forecast of the expected hourly Real-Time Hub Price for such hour of the Operating Day and (ii) zero."

[70] Ewing Testimony 16: 20-23. The current methodology uses the GMM as a statistical model to predict the distribution of Real-Time Hub LMPs for each hour of the next operating day. Inputs are publicly available prior to the clearing of the Day-Ahead Market, with the load forecast, natural gas price, and recent Real-time LMPs being the most impactful inputs. *See* B. Ewing, *Day-Ahead Ancillary Services Market: Overview of Day-Ahead Ancillary Service for NEWEM* at 29, available at https://www.iso-ne.com/static-assets/documents/100029/20251029-08-newem-dasi-post.pdf.

[71] Ewing Testimony 16: 22, 17: 1.

[72] *Id.* 17: 2-3.

[73] IMM Memo 5-7. *See also* Ewing Testimony 6: 9-15, 17: 3-7.

[74] The DA A/S design emerged out of the initial Energy Security Improvements ("ESI") and Day Ahead Ancillary Services Initiative ("DASI") presented in the stakeholder process.

[75] Ewing Testimony 16: 1-8. *See* C. Geissler and Z. Murra Anton, *DASI: Procure and transparently price services required for a reliable operating plan in the Day-Ahead Energy Market,* Presentation to NEPOOL Markets Committee dated Nov. 8-10, 2022 at 53; B. Ewing and A. Withers, *DASI: Procure and price services required for a reliable operating plan in the Day-Ahead Energy Market*, presentation to NEPOOL Markets Committee dated Dec. 6-8 at 5; *available at* https://www.iso-ne.com/static-assets/documents/2022/11/a08_mc_2022_11_08-10_dasi_presentation.pptx and a07a_mc_2022_12_06_08_dasi_presentation_rev1.pptx.

an obligation when the Real-Time Hub LMP exceeds the Strike Price but remains below their marginal cost. When the Strike Price is set too high, the performance incentives provided by the design are attenuated because the likelihood and magnitude of a non-zero close-out charge is reduced.[76]

To better align the Strike Price with the marginal energy costs for DA A/S sellers, the Proposed Adjustments introduce a floor to the Strike Price based upon a marginal cost estimate for an efficient CT generator. This floor uses a relatively efficient representative heat rate (9 MMBtu/MWh) and the least-cost fuel index, including associated regional emissions costs.[77]

Under the Proposed Adjustments, the Strike Price in a given hour will be the *greater of* (i) the current calculation using the GMM, including a $10 baseline adder, and (ii) the floor value derived from the marginal costs estimate of an efficient CT generator based on the lowest-cost distillate fuel index and associated emissions costs.[78]

The proposed floor is designed to remain below the marginal cost of most DA A/S suppliers by using a relatively efficient heat rate and lowest-cost fuel and emissions assumptions. This approach largely preserves the performance incentives inherent in the current design while narrowing the gap between the Strike Price and the costs of physical hedging, thereby reducing DA A/S Offer prices and risk premiums, and encouraging greater participation.[79]

The Proposed Adjustments to the Strike Price thereby strike a balance between competing concerns: setting the Strike Price too low may increase offer prices and decrease participation with limited reliability benefit, while setting it too high may reduce performance incentives. Setting a Strike Price far below the short-run marginal cost of a resource does not increase their incentives but does increase the close-out related risks. Conversely, participation in offering DA A/S may increase with a higher Strike Price and a lower risk of close-out.[80]

For the historical period March 2025 – February 2026, the ISO estimates that the Strike Price floor would be approximately $141/MWh on average, and would set the Strike Price in approximately 90% of these historical hours, with the current GMM calculation determining the Strike Price in the remaining 10% of hours.[81] Backcast results for the same study period indicate

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[76] Ewing Testimony 16: 9-17. *See* IMM Memo at 6 (recommending an upward adjustment to the Strike Price to better align it with the short-run marginal costs of combustion turbine ("CT") DA A/S providers).

[77] *See* Ewing Testimony 18: 3-20, 19: 1-2, 5-21, 20: 1-4.

[78] *Id.* 18: 7-15, 20: 6-16.

[79] *Id.* 19: 5-10.

[80] *Id.* 18: 16-20, 19: 1-2. As the Strike Price is adjusted upward and better aligns the short-run marginal costs of one category of resources, it may exceed the short-run marginal costs of other resources and thereby reduce their performance incentives. Therefore, any approach comes with tradeoffs given the use of a single, system-wide hourly Strike Price and the differences among suppliers' technologies and related costs of producing energy. *Id*. 16: 9-17.

[81] *Id*. 22: 9-12.

that the proposal would have reduced the spread between Strike Prices and marginal costs across all conditions, particularly during low-load or low gas price periods.[82]

This analysis shows that:

- The proposed floor significantly narrows the spread between hourly Strike Prices and the marginal costs of DA A/S suppliers.

- The floor has greater impact in terms of increasing the Strike Price and also decreasing the performance incentives for DA A/S sellers during low-load hours and low gas price periods (*i.e*., hours with lower risk of reliability issues).

- Impacts are more limited in high-load or high gas price periods, where existing GMM-based Strike Prices often already exceed the floor. In such periods, the performance incentives for DA A/S sellers are largely retained (relative to the current design).

- CCs experience larger reductions in performance incentives, while CT units are less affected.[83]

These results suggest the proposal improves alignment between Strike Prices and marginal costs of energy for historically observed sellers of DA A/S, while retaining incentives when they are most critical, such as during high-load conditions. The GMM-based calculation, including the $10/MWh adder, continues to govern in conditions where it produces higher values, ensuring responsiveness to system tightness.[84]

Nor will the proposed Strike Price floor result in resources with lower short-run marginal costs of energy being required to provide uncompensated reserves. All resources with the required physical capability are eligible to offer into the DA A/S market and receive compensation from this market if they are selected to provide the required services, regardless of whether their short-run marginal costs of energy are high or low. Additionally, this proposed change will serve to reduce the risk associated with taking on a DA A/S award for all resources (again, regardless of short-run marginal costs) in that it reduces the likelihood of a non-zero closeout charge.[85]

In summary, the proposal sets the Strike Price as the greater of the current GMM calculation or a marginal cost-based floor for an efficient distillate-fired CT generator. By selecting an efficient heat rate and a low-cost fuel index, the Proposed Adjustments should increase the Strike Price to a level conceptually aligned with the short-run marginal costs of CTs in most hours. Insofar as it reduces the likelihood of very low Strike Prices, the proposal lowers close-out risk and expected close-out charges, reducing the cost of participation. This, in turn, is

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[82] *Id*. 22: 13-15.

[83] *Id.* 22: 15-19, 23: 1-14.

[84] *Id.* 23: 16-21.

[85] *Id*. 22: 1-6.

expected to lower DA A/S offer prices while maintaining performance incentives in critical hours and supporting reliable market outcomes. With a floor in place to prevent the Strike Price from falling too low, the DA A/S design, as adjusted, should strike a reasonable and cost-effective balance between bringing the Strike Price more in line with the marginal cost of observed sellers of DA A/S while still incentivizing performance and preserving the incentives of the design for a majority of sellers and at times when the system is at greatest risk.[86]

C. Mitigation Considerations and Proposed Adjustment to the Impact Test Threshold

The ISO also proposes adding a floor of $3/MWh in calculating the Impact Test threshold for mitigation.[87] This will prevent the Impact Test threshold from falling below $3/MWh in hours when the Expected Close-Out is above $0/MWh and below $2/MWh.[88]

Under the current calculation method, the threshold for failing the Impact Test generally comes out to $3/MWh when the Expected Close-Out is $0/MWh and also when it is $2/MWh. However, mathematically, the threshold for the Impact Test generally becomes more stringent (*i.e*., lower than $3/MWh) when the Expected Close-Out is between $0/MWh and $2/MWh. As explained in the accompanying Mazur Testimony, this is an unintended feature of the Impact Test threshold calculation as a result of the $2/MWh minimum under the Conduct Test.[89]

If left unchanged, this feature may result in more frequent violations of the Impact Test and the potential for over-mitigation in low-priced hours when market power is not a significant concern.[90] The Proposed Adjustments therefore include a proposal to apply a $3/MWh floor to the Impact Test threshold to prevent this outcome. This proposed change also aligns with the recommendation of the External Market Monitor.[91]

D. The Proposed Adjustment to NCPC for DA Cleared Imports Without a Corresponding Real-Time Supply Offer

The DA A/S design requires that Day-Ahead External Transactions have a corresponding Real-Time supply offer in order to be paid the FER Price. A Day-Ahead cleared import without a corresponding Real-Time offer is ineligible to receive the FER Price.[92]

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[86] *Id*. 23: 23-30, 24: 1-5.

[87] Tariff Redlines Section III.A.8.1.2; Mazur Testimony 3: 1-2.

[88] Mazur Testimony 8: 19-22.

[89] *Id*. 9: 2-5, 8-9, 10: 2-12.

[90] *Id.* 11: 1-4. The ISO's Market Monitoring Applications team will calculate and apply when appropriate the newly proposed floor when determining the Strike Price, and it will use the resulting Strike Price calculation when determining DA A/S Benchmark Levels used for review and potential mitigation by the IMM.

[91] *Id*. 11: 6-10, 12-14. *See* Potomac Analytics, 2024 Assessment of the ISO-NE Electricity Markets (recommendation 2024-2) at p. 39, available at https://www.iso-ne.com/static-assets/documents/100025/iso-ne-2024-emm-report-final.pdf.

[92] Section III.3.2.1(q)(4)(ii). *See* Mazur Testimony 4: 3-8.

The Proposed Adjustments include a minor change to the Day-Ahead NCPC rules such that the FER Price is considered (for accounting purposes only) as part of the hourly revenue for Day-Ahead cleared imports regardless of whether there is a corresponding Real-Time transaction. This adjustment is necessary to prevent Day-Ahead imports that are ineligible to receive the FER Price—because they do not have a corresponding Real-Time offer—from effectively receiving that price through a Day-Ahead Market NCPC Credit.[93] Occurrences of this have been rare but warrant prevention.[94]

To illustrate, consider a simple example in which a 1 MW Day-Ahead cleared import is on the margin for energy supply in an hour when the FER constraint binds.[95] Consequently, assume the import's energy offer ($60/MWh) is reflected in the Day-Ahead LMP and the FER Price as follows: Day-Ahead LMP $50/MWh and FER Price $10/MWh. Further assume this Day-Ahead cleared import has no corresponding Real-Time offer and, therefore, is ineligible for the FER Price. Under the current Day-Ahead NCPC accounting rules, this import would not have the FER price reflected in its hourly revenue. Therefore, its DA NCPC credit calculation under current rules will be:

· Hourly Revenue = DA LMP = $50/MWh

· Hourly Cost = Supply offer = $60/MWh

· DA NCPC credit = Cost – Revenue = $10/MWh

Although this import would be ineligible to receive the FER Price, it effectively receives that price through its Day-Ahead Market NCPC Credit. This would not be the case if the FER Price were included in its hourly revenue (irrespective of eligibility) for NCPC accounting purposes. Under such a revised approach, the import would have an hourly revenue of $60/MWh for NCPC accounting purposes (*i.e.*, the Day-Ahead LMP plus the FER price, for a total of $60/MWh in the example) and therefore receive no Day-Ahead Market NCPC Credit.[96]

A simple "fix" of the Tariff requires only a small adjustment to the current NCPC "Hourly Revenue" accounting language as follows:[97]

> **III.F.2.3.1.3. Hourly Revenue**. The Day-Ahead revenue for a pool-scheduled External Transaction import at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, not subject to the credit conditions specified in Section III.3.2.1(q)(4)(ii)….

[93] Mazur Testimony 2: 16-20.

[94] *Id*. 6: 16-18, 7: 1-2.

[95] *Id.* 6: 1-2.

[96] *Id.* 6: 4-12.

[97] *Id*. 7: 8-19.

In this way the FER Price or its equivalent through NCPC credits is paid only to resources that help ensure a reliable next-day operating plan, which does not include an import transaction without a corresponding Real-Time supply offer.[98]

VI. STAKEHOLDER PROCESS

The Proposed Adjustments to the DA A/S were considered through the complete NEPOOL Participant Processes. The NEPOOL Markets Committee reviewed the Proposed Adjustments during three meetings, culminating in a Markets Committee roll call vote at its June 9, 2026 meeting. With a 64.54% vote in favor, the Markets Committee recommended that the Participants Committee support the Tariff Revisions.[99] Also at that meeting, the Markets Committee considered a Market Participant-sponsored amendment to remove the Strike Price floor from the ISO's proposal, which was not supported.[100] Subsequently, at its June 16, 2026 meeting, the Participants Committee considered a main motion to support the Markets Committee-recommended Tariff Revisions. With a 68.78% vote in favor, the Participants Committee voted to support the Proposed Adjustments,[101] and voted not to support the Market Participant-sponsored amendment.[102]

VII. REQUESTED EFFECTIVE DATE

The ISO requests that the Commission permit the Proposed Adjustments to the Tariff to become effective without suspension or hearing on September 14, 2026, 60 days from the date of this Filing Letter, with an implementation date of October 22, 2026, for the next Operating Day on October 23, 2026.

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[98] *Id.* 7: 20-22.

[99] The result of the roll-call vote at the Markets Committee meeting was as follows: Generation Sector (0% in favor, 16.67% opposed, 0 abstentions); Transmission Sector (16.67% in favor, 0% opposed, 0 abstentions); Supplier Sector (8.33% in favor, 8.33% opposed, 5 abstentions); Publicly Owned Entity Sector (16.67% in favor, 0% opposed, 0 abstentions); Alternative Resources Sector (6.2% in favor, 10.46% opposed, 1 abstention); and End User Sector (16.67% in favor, 0% opposed, 1 abstention).

[100] NEPOOL will file supplemental comments describing the Market Participant-sponsored amendment and the voting outcome.

[101] The following Participants opposed: Brookfield Renewable Trading and Marketing LP; Canal Marketing LLC; Constellation Energy Generation, LLC; CPV Towawntic, LLC; FirstLight Power Management LLC; Generation Bridge Connecticut Holdings, LLC; H.Q. Energy Services (US) Inc.; Nautilus Power, LLC; NextEra Energy Resources, LLC; Pawtucket Power Holding Company LLC; Shell Energy North America (US), L.P.; Vistra (Dynegy Marketing and Trade, LLC); and Wheelabrator North Andover Inc. The following Participants recorded an abstention: CLEAResult Consulting, Inc.; Cross-Sound Cable Company, LLC; Dartmouth Power Associates LP; Dominion Energy Generation Marketing, Inc.; DTE Energy, Inc.; Emera Energy Companies; Gabel Associates, Inc.; Galt Power Inc.; In Commodities US LLC; Mr. Jon Lamson; Long Island Power Authority; Mercuria Energy America, LLC; Onward Energy (Blue Sky West, LLC); and Vitol Inc.

[102] In addition to this amendment, a Participant offered a procedural amendment to divide the main motion into separate proposals, which failed. As indicated in note 100, NEPOOL will provide further explanation in its supplemental comments.

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 Adjustments submitted herewith do not modify a traditional "rate." Therefore, to the extent necessary, the Filing Parties request waiver of Section 35.13 of the Commission's regulations.[103] Notwithstanding this request for waiver, the Filing Parties submit the following additional information in substantial compliance with relevant provisions of Section 35.13 of the Commission's regulations:

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

- This transmittal letter (*i.e.*, Filing Letter);
- The Testimony of Benjamin Ewing, sponsored solely by the ISO;
- The Testimony of Anna Mazur, sponsored solely by the ISO;
- Marked (Redlined) Sections III.1.8.2, III.1.8.4, III.A.8.1.2, and III.F.2.3.1.3 of the Tariff reflecting the Proposed Adjustments effective by this filing;
- Clean Sections III.1.8.2, III.1.8.4, III.A.8.1.2, and III.F.2.3.1.3 of the Tariff incorporating the Proposed Adjustments effected by this filing; 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 is being sent electronically.

35.13(b)(2) – As noted above, the Filing Parties requests that the Tariff changes (*i.e.,* Proposed Adjustments) become effective on September 14, 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 http://www.isone.com/regulatory/ferc/nepool/gov_prtcpnts_eserved.pdf. An electronic copy of this transmittal letter and the accompanying materials has also been sent to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, and to NECPUC. The names and addresses of these governors and regulatory agencies are shown in the above-referenced list, which is included in this filing. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified in the above referenced list 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 Filing Letter.

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[103] 18 C.F.R. § 35.13 (2019).

35.13(b)(5) – The reasons for this filing are discussed in this Filing Letter.

35.13(b)(6) – As explained above, the Proposed Adjustments for which the ISO holds Section 205 rights reflect the results of the Participant Processes required by the Participants Agreement and reflect the support of the Participants Committee.

35.13(b)(7) – The Filing Parties have no 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 Proposed Adjustments herein do not modify a traditional "rate." The statement required under this Commission regulation is not applicable to this 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 ISO Tariff.

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

IX. CONCLUSION

For the foregoing reasons, the Filing Parties respectfully request that the Commission accept the Proposed Adjustments to the DA A/S design in the Tariff as described herein without condition or change.

Respectfully submitted,

ISO NEW ENGLAND INC.

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Dated: July 16, 2026

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in the above-captioned docket.

Dated at Holyoke, Massachusetts on this 16th day of July 2026.

/s/ Julie Horgan
Julie Horgan
eTariff Coordinator
ISO New England Inc.
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Holyoke, MA 01040
(413) 540-4683

Attachment A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

TESTIMONY OF BENJAMIN EWING
ON BEHALF OF ISO NEW ENGLAND INC.

I. WITNESS IDENTIFICATION

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

A: My name is Benjamin Ewing. I am a Technical Manager in the Market Development department at ISO New England Inc. ("ISO" or "ISO-NE"). My business address is One Sullivan Road, Holyoke, MA 01040.

Q: Please describe your professional experience and qualifications.

A: Since joining the ISO in May 2009, I have held various positions. From May 2009 to October 2011, I was an Analyst in the Market Analysis and Settlements department. From October 2011 until December 2023, I held a series of analyst positions in the Market Development department, culminating in the Principal Analyst role. In these roles, I was responsible for identifying and developing market design improvements for New England's competitive wholesale electricity markets and presenting these market improvements to external stakeholders. In December 2023, I transitioned to the Surveillance and Analysis team of the ISO's Internal Market Monitor ("IMM"), where I performed investigations into participant behavior in the ISO's markets and analyzed market designs and outcomes for efficiency and effectiveness. In September 2025 I transitioned back to the Market Development department, where I now hold the role of Technical Manager.

I previously provided testimony to the Federal Energy Regulatory Commission ("Commission") in support of adopting the Day-Ahead Ancillary Services ("DA A/S") Market and explained how the proposed changes would result in a jointly co-optimized Day-Ahead Energy Market and DA A/S Market (together, "Day-Ahead Market") for both energy and reserves (Docket No. ER24-275-000). I also have provided testimony to the Commission in support of other market rule changes, including revisions to energy market offer caps pursuant to Commission Order No. 831 (Docket No. ER19-2137-000), interim revisions to the energy market offer cap treatment of so-called "fast start" resources (Docket No. ER17-1542-000), changes to natural gas price indices used in determining various threshold prices in ISO markets (Docket No. ER17-337-000), and assorted changes to Net Commitment Period Compensation ("NCPC") credit calculations (Docket No. ER17-2569-000).

Prior to joining the ISO, I received a B.A. in Applied Mathematics from Washington University in St. Louis, and an M.S. in Industrial Engineering and Operations Research from the University of Massachusetts.

II. PURPOSE AND ORGANIZATION OF TESTIMONY

Q: Have you prepared the testimony submitted in this proceeding?

A: Yes. I have prepared this testimony or supervised its preparation.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to support the Proposed Adjustments to the DA A/S design as set forth in the accompanying Filing Letter.[1] My testimony focuses on two of the Proposed Adjustments:

1. Adjusting the Forecast Energy Requirement Demand Quantity ("FER Demand Quantity"), as specified in revised Tariff Section III.1.8.4, to better reflect the expected contribution of front-of-the-meter ("FtM") wind and solar resources to meeting the Forecast Energy Requirement ("FER"); and

2. Setting a floor on the Day-Ahead Ancillary Services Strike Price ("Strike Price"), as specified in revised Tariff Section III.1.8.2, based on the marginal costs of energy of a class of resources empirically observed to sell a significant share of DA A/S (*i.e.*, distillate-fired combustion turbine generators).

Q: Do you support the other Proposed Adjustments to the DA A/S set forth in the Filing Letter?

A: Yes. I presented to stakeholders at the NEPOOL Markets Committee on all the Proposed Adjustments. My colleague Anna Mazur, who assisted with my presentations, will testify separately ("Mazur Testimony") with respect to the remaining two Proposed Adjustments, which I also support. These proposals consist of an adjustment to the Day-Ahead Net Commitment-Period Compensation Credit calculation and introducing a floor price to the Impact Test threshold used for mitigation purposes. I have reviewed the Mazur Testimony and concur in her analysis.

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[1] Capitalized terms used but not defined in my testimony are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff ("Tariff") or the accompanying Filing Letter in the above-captioned docket.

Q: How is your testimony organized?

A: My testimony focuses on two of the Proposed Adjustments. In Section III, I discuss and support the above-mentioned proposal to reduce the FER Demand Quantity to better reflect the expected contribution of FtM wind and solar resources to satisfying the FER constraint in the co-optimized Day-Ahead Market. In Section IV, I discuss and support the above-mentioned proposal to introduce a floor to the Strike Price based upon a marginal cost estimate for an efficient distillate fuel-fired combustion turbine ("CT") generator. In Section V, I briefly discuss an estimate of the impact on costs, subject to certain assumptions and based on a backcast of historical data, that the Proposed Adjustments may have in the aggregate.

Q: What was the impetus for these Proposed Adjustments?

A: The proposals to reduce the FER Demand Quantity to better account for FtM wind and solar resources and to set a floor on the Strike Price are directly responsive to the recommendations of the ISO's IMM.[2] The IMM has been active in observing the operation of the DA A/S Market since inception and communicating its findings to stakeholders. The proposals to adjust the Day-Ahead Market NCPC Credit and introduce a floor to the Impact Test threshold were initiated by the ISO based on its own observations of market outcomes. Together, all the Proposed Adjustments are intended to improve the overall efficiency of the DA/AS design.

[2] *See* D. Naughton, "Recommended Changes to the Day-Ahead Ancillary Services Market," Memorandum to NEPOOL Market Committee dated February 4, 2026 ("IMM Memo"), *available at* https://www.iso-ne.com/static-assets/documents/100032/2026_02-imm-memo-with-daas-recommendations.pdf.

Q: Do the Proposed Adjustments alter the basic design for procuring DA A/S in the Day-Ahead Market?

A: No. The Proposed Adjustments do not alter the basic design of the DA A/S Market to procure and price sufficient reserves in the Day-Ahead Market to reliably meet the region's next-day operating reserve and load forecast requirements. But the Proposed Adjustments do update key parameters of the DA A/S Market design based upon observed outcomes since its implementation in March 2025, with the goal of making the design more efficient.

Currently, the Day-Ahead Market jointly procures and prices operating reserves—ten- and thirty-minute Flexible Response Services ("FRS")—to meet associated ten- and thirty-minute reserve requirements, as well as sixty-minute Energy Imbalance Reserve ("EIR") and physical energy to meet expected Real-Time load through the Forecast Energy Requirement ("FER") constraint.[3] The Strike Price is an hourly value that is published in advance of clearing the Day-Ahead Market, and it is a key component of both the DA A/S Market's call-option settlement design and DA A/S supply offer prices. The FER Demand Quantity is based on the ISO's load forecast, while the Strike Price calculation is based on a Gaussian Mixture Model ("GMM"). Both the FER Demand Quantity and the Strike Price serve as key inputs into the clearing of the jointly-optimized Day-Ahead Market and impact the efficiency of the DA A/S design.

[3] More specifically, the DA A/S design created three new FRS: the Day-Ahead Ten Minute Spinning Reserve ("TMSR"), Day-Ahead Ten Minute Non-Spinning Reserve ("TMNSR"), and Day-Ahead Thirty Minute Operating Reserve ("TMOR"), as described in Tariff Section III.1.8.3, and the corresponding Day-Ahead Ancillary Services Market Obligations, as defined in Tariff Section III.3.2.1(a)(2).

As observed over the last year since inception, the FER constraint in the Day-Ahead Market tends to under-estimate the contribution of FtM wind and solar supply as compared to the ISO's Day-Ahead reliability assessment under its Reserve Adequacy Analysis ("RAA"). This results in a costly market inefficiency, insofar as the Day-Ahead Market may commit additional generation or procure more physical energy supply or EIR than necessary to satisfy the Real-Time load forecast.

Empirical observations further show that a significant share of DA A/S awards have been cleared by CT generators, which are generally (though not exclusively) fueled by distillate oil. The short-run marginal costs of these DA A/S suppliers frequently are well above the Strike Price, creating a range of Real-Time Hub LMPs within which these resources would not be expected to physically cover their DA A/S awards, but would face a positive close-out charge associated with their DA A/S awards. As the IMM has stated: "Suppliers may therefore reflect this closeout risk in higher DA A/S offer prices or, in some cases, opt not to participate [in offering DA A/S] when the expected financial exposure is uneconomic."[4]

The Proposed Adjustments therefore include responsive proposals to (i) adjust downward the FER Demand Quantity to account for the above-noted discrepancy, thereby improving the alignment of the FER constraint with the ISO's reliability assessment and reducing this inefficiency; and (ii) introduce a floor to the Strike Price, thereby improving the alignment of the Strike Price with the estimated marginal cost of an efficient CT

[4] IMM Memo at 5.

resource running on the lowest-cost distillate fuel, including regional emissions costs. I discuss each of these proposals in more detail below.

III. PROPOSED ADJUSTMENT TO THE FER DEMAND QUANTITY

Q: Could you begin by explaining the FER constraint in the Day-Ahead Market?

A: Yes. The FER constraint ensures that cleared Day-Ahead physical energy supply and EIR meet or exceed the ISO's load forecast for each hour. The FER constraint therefore reflects the reliability need to satisfy the Day-Ahead load forecast within the clearing of the Day-Ahead Market and transparently prices that need. Both Day-Ahead energy awards to physical suppliers and EIR awards serve to help satisfy the FER constraint and are compensated at the FER Price.

Q: How is the FER constraint constructed?

A: The FER constraint is generally constructed as follows:

$$\text{Generator}_{\text{DA Energy}} + \text{Import}_{\text{DA Energy}} + \text{Demand Response Resource}_{\text{DA Energy}} + \text{EIR}$$
$$\geq \text{FER Demand Quantity} + \text{Export}_{\text{DA Energy}}$$

Q: How is the FER Demand Quantity determined in the above constraint?

A: The FER Demand Quantity currently is equal to the ISO's hourly load forecast. This forecast reflects the physical supply of energy the ISO expects is needed to meet the next-day demand. Physical energy supply and EIR awards serve to meet this demand.

Q: Does the FER constraint consider the contribution from renewable energy resources like wind and solar?

A: Yes, but this depends. The expected output of behind-the-meter ("BtM") generation (*i.e.*, solar) is fully accounted for in the FER constraint through a reduction in the load forecast. To use a simple example, if the gross expected New England load is equal to 12,500 MW, and expected BtM generation is equal to 500 MW, then the load forecast is adjusted to 12,000 MW.

In contrast, FtM wind and solar resources tend not to be fully accounted for in the FER constraint as it is currently applied in the Day-Ahead Market. Historically, these resources clear Day-Ahead energy awards that are significantly below their expected Real-Time output. While this varies month-to-month, FtM wind and solar resources cleared on average approximately 40 percent of forecasted supply over a recent historical period. As a result, the current implementation of the FER constraint understates the expected contribution of FtM wind and solar to meeting forecast Real-Time load.

Q: By comparison, how does the ISO account for FtM renewable output in its reliability processes?

A: In contrast, the ISO's RAA process (that I mentioned above), evaluates the Day-Ahead solution's ability to meet forecasted load and reserve requirements. The RAA is the ISO's standard reliability evaluation conducted in the Day-Ahead timeframe after clearing the Day-Ahead Market. The RAA considers all Day-Ahead committed and fast-start generation using Real-Time Supply Offers. Generally, this means that the RAA models the output from FtM wind and solar resources at a level consistent with their resource-specific Real-Time forecasts, as adjusted for any operational constraints (*e.g.*, a binding transmission constraint). Importantly, the FtM wind and solar resources are generally counted toward the ISO's reliability needs at the ISO's forecast of their expected Real-Time output, which tends to be greater than their corresponding cleared Day-Ahead awards. In doing so, the RAA process efficiently accounts for the energy that the ISO expects to be produced in Real-Time, and thereby avoids the potential for committing the system beyond what is required to meet reliability objectives.

Q: Is it correct that the ISO's system operators rely on FtM wind and solar resources at their forecasted output, even if such resources clear less than that forecasted output in the Day-Ahead Market?

A: Yes. ISO system operators establish a reliable next-day operating plan based upon their expectations of next-day operating conditions. The forecasted output of FtM wind and solar resources provides a more accurate estimate of their Real-Time energy production than do their Day-Ahead awards. Consequently, system operators rely upon FtM wind and solar forecasts when assessing whether a next-day operating plan is reliable. This approach has been employed since 2014, when such forecasts started to become available, and has proven effective.

Q: Does the current accounting of FtM wind and solar in the FER constraint result in a market inefficiency?

A: Yes. This inefficiency is highlighted by the mismatch between the FER constraint and the RAA process as discussed above. Because the FER constraint does not fully reflect expected FtM renewable output, the Day-Ahead Market may commit additional resources, or clear additional Day-Ahead energy or EIR, to meet the forecasted load. This results in over-commitment or over-clearing relative to the reliability need. Procuring more supply than is needed to satisfy a reliability requirement is costly and inefficient. The cost associated with such over-commitment or over-clearing, which is not necessary to meet reliability requirements, is ultimately borne by consumers.

Q: Which Proposed Adjustment, if any, addresses this inefficiency?

A: To address the potential for the FER constraint to clear more supply than needed to satisfy the reliability need, the proposal adjusts the FER Demand Quantity downward to account for expected FtM wind and solar generation that is forecasted to occur in Real-Time but is not expected to clear in the Day-Ahead Market. Because the actual amount of FtM wind and solar energy and EIR supply that clears in the Day-Ahead Market is not known until after the market has cleared, the ISO will rely on the initial "case" of the ISO's Day-Ahead Market clearing process as a reliable proxy for forecasting the expected amount of FtM wind and solar energy and EIR supply that will clear in the Day-Ahead Market.

Q: How will the adjusted FER Demand Quantity be calculated?

A: The ISO proposes to adjust the FER Demand Quantity (currently, set equal to the load forecast for each hour under Tariff Section III.1.8.4) by the expected amount of forecasted but uncleared Real-Time FtM wind and solar generation, as follows:

Proposed FER Demand Quantity = Load Forecast – max(FtM wind/solar forecast – Expected FtM wind/solar Cleared Energy and EIR, 0)

In other words, the FER Demand Quantity will equal the load forecast less the positive difference between (i) forecasted FtM wind and solar output and (ii) the amount of such generation expected to clear the Day-Ahead Market (including both energy and EIR).

Q: Do you expect that the Proposed Adjustment to the FER Demand Quantity will result in increased out-of-market commitments or increased uplift payments?

A: No. The Proposed Adjustment to the FER Demand Quantity better aligns the FER constraint with the existing RAA process, and it is the RAA process that determines whether any additional, out-of-market commitments may be required. Improving the alignment of the FER constraint and the RAA process will not serve to increase reliance on out-of-market commitments or produce associated uplift payments.

Q: Is the ISO concerned that the Proposed Adjustment to the FER Demand Quantity will negatively impact system reliability?

A: No. Again, this is because the proposed change to the FER Demand Quantity better aligns the DAM with the long-standing RAA process. The intent of implementing the DA A/S market generally, and applying the FER constraint specifically, is to reflect the ISO's reliability needs (*i.e.*, those considered by the RAA process) through a market construct. With this proposed change, the DAM will be more closely aligned with the RAA process, which has been employed by the ISO to produce reliable next-day operating plans for decades, and which began incorporating the forecasted output of intermittent renewable resources in 2014. Rather than negatively impacting reliability, this proposed change will simply avoid the potential that is inherent in the current application of the FER constraint for over-committing or over-clearing the system relative to the ISO's reliability need. As I have noted, this over-commitment or over-clearing is unnecessary and can be costly for consumers.

Q: Does the Proposed Adjustment to the FER Demand Quantity capture uncertainty associated with the output of FtM wind and solar resources? If not, should it do so?

A: No, the Proposed Adjustment to the FER Demand Quantity does not explicitly account for the uncertainty associated with the output of FtM wind and solar resources, nor should it. The FER (*i.e.*, the "*Forecast* Energy Requirement") constraint is intended to reflect the ISO's *expectation* of (1) the load forecast, and (2) the set of resources able to satisfy that load forecast. Both items (1) and (2) entail a degree of uncertainty: the load forecast is inherently uncertain, as is the output of all resources, including wind and solar resources. The existing implementation of the FER constraint captures item (1), while the FER constraint with the Proposed Adjustment to the FER Demand Quantity will fully capture both (1) and (2). While uncertainties exist in both the current and proposed implementations of the FER constraint, it is not the purpose of this constraint to reflect both the ISO's expectation and uncertainties around that expectation. The ISO separately procures Flexible Response Services ("FRS," a suite of 10- and 30-minute reserve products) in the DAM and designates Operating Reserves in Real-Time for the express purpose of responding quickly to unanticipated events that do not align with the ISO's next-day expectations. While requirements for these 10- and 30-minute reserve products have historically been established based upon the first and second contingencies on the system, this fast-ramping capability is relied upon to respond to unexpected system events of all kinds, including instances when FtM wind and solar output deviates from expectation or loads come in higher than expected. The ISO has discretion to set these requirements based upon system needs. In a future scenario with much greater wind and solar resource penetration, and greater uncertainty regarding the associated output, the ISO may choose to procure more 10- and 30-minute reserves to address this uncertainty. In addition, the ISO currently has discussed with stakeholders a future workplan item dedicated to evaluating uncertainty-related constraints and products, which may more directly handle uncertainty around items such as the load forecast and wind and solar output.

Q: How is this proposed change reflected in the Tariff redlines?

A: This change is reflected in the Tariff redlines as follows:

> **III.1.8.4 Forecast Energy Requirement Demand Quantity**. For each hour of the Operating Day, the Forecast Energy Requirement Demand Quantity shall be: ~~equal to~~
>
> (1) the ISO forecast for the total load in the New England Control Area produced pursuant to Section III.1.10.1A(h) of this Market Rule 1, less
>
> (2) the greater of (i) the forecast of front-of-the-meter dispatchable wind and solar resources' total real-time energy supply, as adjusted for any expected operating conditions, less the total energy supply and ancillary services from such resources forecast to clear in the Day-Ahead Market and (ii) zero.

Q: What are expected benefits of the Proposed Adjustment to the FER Demand Quantity?

A: The proposal provides several benefits:

- **Improved efficiency**: It aligns the treatment of FtM wind and solar in the FER constraint with their treatment in the ISO's reliability assessments, reducing unnecessary Day-Ahead commitments or over-clearing of Day-Ahead energy or EIR supply.

- **Preserved incentives**: FtM wind and solar resources continue to receive the FER Price for any energy or EIR they clear, with no compensation for uncleared supply.

- **Adaptive design**: If FtM wind and solar resources increase their Day-Ahead participation, the adjustment will naturally shrink.

- **Consistency**: The proposal better aligns the treatment of FtM and BtM renewable resources by ensuring both are reflected in the FER constraint based on expected output.

Q: What is the expected quantitative impact of the proposal?

A: The ISO estimates that the adjustment would have reduced the effective load used to calculate the FER Demand Quantity by approximately 422 MW on average for the period of March 2025 – February 2026, with no adjustment occurring in fewer than 3 percent of hours.

Q: Please summarize the rationale for the Proposed Adjustment to the FER Demand Quantity.

A: The current FER framework understates the contribution of FtM wind and solar generation relative to the ISO's own reliability assessments, leading to inefficient over-commitment or over-clearing in the Day-Ahead Market. The Proposed Adjustment resolves this discrepancy by aligning the FER constraint with the ISO's reliability assessment, thereby reducing inefficiencies and associated costs while maintaining appropriate market incentives.

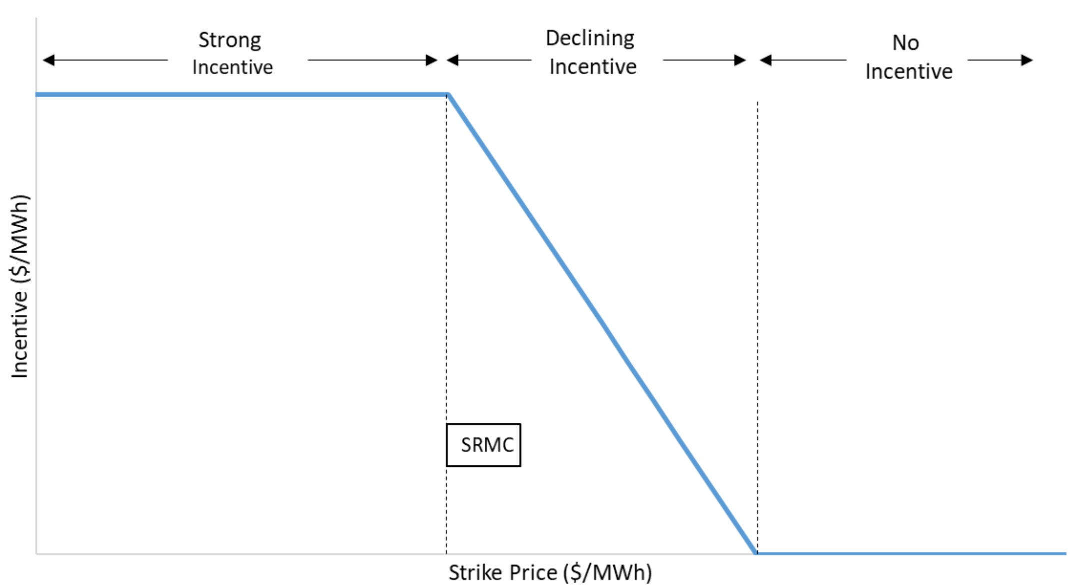
IV. PROPOSED ADJUSTMENT TO THE STRIKE PRICE

Q: What is the current methodology for calculating the Day-Ahead Ancillary Services (DA A/S) Strike Price under the Tariff?

A: The current methodology sets the Strike Price for each hour as the expected next-day Real-Time Hub Locational Marginal Price ("LMP") plus a $10/MWh baseline adder. This is set forth in Tariff Section III.1.8.2.

Q: How does the Strike Price affect incentives under the DA A/S design?

A: The DA A/S call option settlement design provides efficient performance incentives when the Strike Price is at or below a resource's marginal cost of energy supply. The incentives provided by the DA A/S design reflect the difference between a seller's expected net revenue if its resource is able to operate in Real-Time, and its expected net revenue if its resource is not able to operate in Real-Time. The relationship between the Strike Price and the design's incentives is illustrated in the figure below.



The design provides strong, consistent incentives when the Strike Price falls below the resource's short-run marginal cost ("SRMC" in above figures). When the Strike Price exceeds the resource's short-run marginal cost, the incentives begin to decline toward zero. This decrease in incentives occurs because the potential for a non-zero closeout charge decreases as the Strike Price increases. When the Strike Price exceeds a DA A/S seller's short-run marginal cost, that seller no longer faces the full cost of its non-performance (via the DA A/S closeout charge) if it is called upon to run in real-time and is unable to operate.

Any approach to adjusting the Strike Price comes with tradeoffs, as there is no perfect solution given (i) the heterogeneity of DA A/S suppliers' technologies and energy costs, and (ii) the use of a uniform, system-wide hourly value for the Strike Price. When the Strike Price is set too low, it provides limited incremental reliability value and resources are not economically incentivized to perform when the Real-Time Hub LMP exceeds the Strike Price but remains below their marginal cost (*i.e.*, increased close-out-related risks). When the Strike Price is set too high, the performance incentives provided by the design are attenuated because the likelihood and magnitude of a non-zero close-out charge is reduced.

Q: Why does the current Strike Price methodology present issues?

A: Since the inception of the co-optimized design over a year ago, both the ISO and IMM have been monitoring DA A/S outcomes. The Strike Price has been observed to frequently fall well below the marginal cost of energy of a significant portion of DA A/S sellers. We also have observed that CT generators have cleared a majority of DA A/S awards, although many other resources have participated, including CC generators. These CTs typically run on higher-cost distillate fuels (No. 2 Oil, ULS Kerosene, ULS Diesel, and LS Jet Kerosene), while CCs typically run on natural gas. Because the Strike Price may be below these resources' short-run marginal costs, suppliers may face a gap between the Strike Price and the cost of physically hedging in Real Time. This dynamic can lead to: (i) increased risk premiums in DA A/S supply offers; or (ii) reduced participation in the DA A/S market because of the closeout risk.

Q: What are the typical characteristics of DA A/S sellers?

A: As shown in the table below, which reflects data from March 2025 – February 2026, a majority of DA A/S awards are cleared on CT generators.

Asset Type	DA A/S Cleared GWh	Percent DA A/S Awards Cleared
CT	13,600	64.7%
CC	6,041	28.7%
Other	1,387	6.6%

CTs frequently rely on higher-cost distillate fuels, while CCs typically use natural gas. CTs have a wide range of efficiencies (as indicated by their heat rate, in MMBtu/MWh), while the distribution of CC heat rates is much tighter.

	Full Load Average Heat Rate Statistics					
Type	10th Pctl	25th Pctl	Median	Average	75th Pctl	90th Pctl
CC	7	7	7	8	7	9
CT	9	10	11	12	14	15

Q: What is the Proposed Adjustment to the Strike Price calculation?

A: To better align the Strike Price with the marginal energy costs for DA A/S sellers, the Proposed Adjustment introduces a floor to the Strike Price based upon a marginal cost estimate for an efficient combustion turbine ("CT") generator. This floor uses a relatively efficient representative heat rate (9MMBtu/MWh) and the lowest-cost fuel index, including associated regional emissions costs. The Strike Price for each hour will be set as the greater of:

(i) the current GMM-based calculation (including the $10/MWh baseline adder); or

(ii) a floor derived from an estimate of the marginal cost of an efficient CT generator, based on:

- a heat rate of 9 MMBtu/MWh;
- the lowest-cost distillate fuel index; and
- applicable regional emissions costs.

The Proposed Adjustment seeks to strike a balance between competing concerns: setting the Strike Price too low may increase offer prices and decrease participation with limited reliability benefit, while setting it too high may reduce performance incentives. Setting a Strike Price far below the short-run marginal cost of resources does not increase their incentives but does increase the close-out related risks. Conversely, participation in offering DA A/S may increase with a higher Strike Price and a lower risk of close-out charges.

Q: Why did the ISO choose a proposed Strike Price floor based on the characteristics of an efficient CT using the lowest-cost distillate fuel?

A: The proposed floor is designed to remain below the marginal cost of most DA A/S suppliers by using a relatively efficient heat rate and lowest-cost fuel and emissions assumptions. This approach largely preserves the performance incentives inherent in the current design while narrowing the gap between the Strike Price and the costs of physical hedging, which should tend to reduce DA A/S Offer prices and risk premiums and encourage greater participation.

Using efficient CT characteristics will help ensure that the Strike Price is not above the short-run marginal costs of the oil-fired fast-start fleet, which the system relies upon to respond to challenging and unanticipated reliability conditions. These resources clear a significant share of DA A/S awards in the winter and summer. This may reduce incentives for some sellers—primarily CC generators—clearing DA A/S on gas-fired resources. However, our analysis indicates that this proposed approach to a Strike Price floor will minimally reduce incentives for the resources clearing DA A/S during highest load conditions (in summer) and during the highest fuel-price conditions (in winter).

The proposal thus seeks to balance two goals: (i) increasing the Strike Price to better align with the short-run marginal costs of most sellers of DA A/S; and (ii) reducing incentives the least for all DA A/S sellers in hours when reliability risk is highest.

Notably, the ISO also will continue to evaluate ways to improve the performance of the GMM in order to produce more accurate calculations of expected Real-Time Hub LMPs (and thereby more accurate values for the Strike Price), as well as improved calculations of Expected Close-Outs.

Q: Would you describe further how the floor to the Strike Price will be calculated?

A: Yes. The proposed Strike Price will be the greater of (i) the expected Real-Time LMP – currently calculated by the GMM – plus a $10/MWh baseline adder, and (ii) the newly-calculated Strike Price floor.

For implementing the Strike Price floor, the ISO proposes to use a 9 MMBtu/MWh heat rate and the lowest-cost index price among the four distillate-fuels used by the CTs observed to clear DA A/S awards: Ultra Low Sulfur Kerosene ("ULSK"), Ultra Low Sulfur Diesel ("ULSD"), Low Sulfur Jet Kerosene ("LSJK") and No.2 Oil ("No2"). Costs will include fuel prices and regional emissions costs (in $/MMBtu). For example, No.2 Oil generally has the lowest cost historically. The floor on the Strike Price (*i.e.*, "K") will be calculated as follows:

$$K_{floor} = 9\ \text{MMBtu/MWH} \times \text{Min}(ULSK_{cost}, ULSD_{cost}, LSJK_{cost}, No2_{cost})$$

Q: How is this reflected in the Tariff redlines?

A: The proposed Tariff redlines allow for the Strike Price to be determined by either the current GMM-based methodology or the value derived in accordance with the new floor price as follows:

> **III.1.8.2 Day-Ahead Ancillary Services Strike Price**.(a) For each hour of the Operating Day, the ISO shall specify the Day-Ahead Ancillary Services Strike Price in $/MWh. The value of the Day-Ahead Ancillary Services Strike Price represents an amount that is the greater of the values calculated in accordance with subsections (1) and (2) below:
>
> (1) the greater of (i) $10/MWh greater than a forecast of the expected hourly Real-Time Hub Price for such hour of the Operating Day and (ii) zero; and (2) a floor value derived in accordance with subsection (c) below.

The redlines further state that the floor value is determined by the ISO's estimate of the marginal cost of a distillate-fired CT generator, reflecting regional emissions costs and the lowest-priced distillate fuel available:

> (c) The floor value in subsection (a)(2) above shall be determined daily based on the marginal cost of supplying energy by an efficient, distillate-fired combustion turbine generator, reflecting regional emissions costs and the lowest-priced distillate fuel available. The ISO shall describe to Market Participants the heat rate, emissions cost, and fuel prices that it uses to determine the value in subsection (a)(2).

Q: What happens if the information for setting a floor price is not available on a day for some reason or circumstances beyond the ISO's control?

A: In such an unusual event, the Tariff redlines expressly provide that "the ISO shall determine the Day-Ahead Ancillary Services Strike Price using the best forecast and floor value available and shall disclose the use of such substitute method to Market Participants as soon as practicable."[5]

Q: Will the proposed Strike Price floor result in resources with lower short-run marginal costs of energy being required to provide uncompensated reserves?

---

[5] *See* Tariff Redline Section III.1.8.2(d).

A: No. All resources with the required physical capability are eligible to offer into the DA A/S Market and receive compensation from this market if they are selected to provide the required services, regardless of whether their short-run marginal costs of energy are high or low. Additionally, this proposed change will serve to reduce the risk associated with taking on a DA A/S award for all resources (again, regardless of short-run marginal costs) in that it reduces the likelihood of a non-zero closeout charge.

Q: Based on historical back-testing, how often is the floor expected to determine the Strike Price?

A: For the historical period March 2025 – February 2026, the ISO estimates that the floor price would be approximately $141/MWh on average; and the floor price would set the Strike Price in approximately 90% of these historical hours, with the current GMM calculation determining the Strike Price in the remaining 10% of hours.

Backcast results for the same historical period indicate that the proposal would have reduced the spread between Strike Prices and the marginal costs of energy for DA A/S suppliers across all conditions, particularly during low-load or low gas price periods. This analysis, which I presented to stakeholders in the NEPOOL Markets Committee,[6] shows that:

- The proposed floor significantly narrows the spread between hourly Strike Prices and the marginal energy costs of DA A/S suppliers.

[6] *See* "Day-Ahead Ancillary Services Post-Implementation Adjustments: Targeted changes to the DA A/S design based on IMM recommendations," NEPOOL Markets Committee, April 14, 2026, slides 23-28, *available at* https://www.iso-ne.com/static-assets/documents/100034/a02_mc_2026_04_14-16_daas_post_implementation_adjustment.pdf.

- The floor has greater impact in terms of increasing the strike price (and thereby narrowing the spread between the hourly Strike Price and the marginal energy costs of DA A/S suppliers) and also decreasing the performance incentives for DA A/S sellers during low-load hours and low gas price periods, when reliability risks are less of a concern.

- The floor has a smaller impact in terms of increasing the Strike Price and decreasing performance incentives in high-load or high gas price periods, where existing Strike Prices often already exceed the floor. In such periods of heightened reliability risk, the performance incentives for DA A/S sellers are largely retained (relative to the current design).

- CCs experience larger reductions in performance incentives, while CT units are less affected.

These results indicate that the proposal improves alignment between Strike Prices and marginal costs of energy for a large share of the historically observed sellers of DA A/S, while retaining incentives when they are most critical, such as during high-load conditions. The GMM-based calculation, including the $10/MWh adder, continues to govern in conditions where it produces higher values, ensuring responsiveness to system tightness.

Q: Could you please summarize the overall expected benefits of the proposal?

A: Yes. The proposal sets the Strike Price as the greater of the current GMM calculation or a marginal cost-based floor for an efficient distillate-fired CT generator. By selecting an efficient heat rate and a low-cost fuel index, the Proposed Adjustment should increase the Strike Price to a level conceptually aligned with the short-run marginal energy costs of CTs in most hours. Insofar as it reduces the likelihood of very low Strike Prices, the proposal lowers closeout risk and expected closeout charges, reducing the cost of participation. This, in turn, is expected to lower DA A/S offer prices while maintaining performance incentives in critical hours and supporting reliable market outcomes. With a floor in place to prevent the Strike Price from falling too low, the DA A/S design, as adjusted, should strike a reasonable and cost-effective balance between bringing the strike price more in line with the marginal cost of observed sellers of DA A/S while still incentivizing performance and preserving the incentives of the design for a majority of sellers and at times when the system is at greatest risk.

V. ESTIMATED IMPACT ON COSTS OF PROPOSED ADJUSTMENTS

Q: Do you have any estimate of the impact on costs that the Proposed Adjustments may have in the aggregate?

A: Using a backcasting methodology and historical data, the ISO estimates that the Proposed Adjustments, plus the reduction to the Non-Performance Factor, would have reduced the first year (March 2025 through February 2026) incremental costs of the DA A/S as co-optimized in the Day-Ahead Market by $292 million. This represents approximately a 30% reduction. As a disclaimer, these estimates are not predictions of future results and are dependent on assumptions with respect to DA A/S behavior and participation, as I previously described to NEPOOL stakeholders.[7] I must emphasize that actual results may vary considerably based on future market conditions, including changes in participation and offer behavior by resources.

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[7] *See* my presentation titled *Day-Ahead Ancillary Service Post-Implementation Adjustment: Targeted changes to the DA A/S design based on IMM recommendations*, May 12, 2026, NEPOOL Markets Committee, available at https://www.iso-ne.com/static-assets/documents/100035/a06_mc_2026_05_12-14_daas_post_implementation_adjustments_presentation.pdf.

VI. 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 16, 2026.

/s/ Benjamin Ewing

Benjamin Ewing, Technical Manager, ISO New England, Market Development

Attachment B

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

TESTIMONY OF ANNA MAZUR
ON BEHALF OF ISO NEW ENGLAND INC.

I. WITNESS IDENTIFICATION

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

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

Q: Please describe your responsibilities in your role at the ISO.

A: My responsibilities include supporting the development of new market designs and enhancing existing ones to improve the wholesale electricity markets and operational performance.

Q: Please describe your past professional experience and education.

A: Prior to joining the ISO, I earned a Master of Science in Energy and Resources from the University of California, Berkeley.

Prior to graduate school, I worked at Wood Mackenzie, in the Supply Chain practice area. In that role, I led strategic sourcing and energy procurement initiatives for utilities, supported regulatory testimony, and conducted market analysis across wholesale power markets. I also have experience in energy research through my roles at Calpine and the California Public Utilities Commission. At Calpine, I conducted research on carbon capture, storage, and utilization technologies. At the California Public Utilities Commission, I researched alternative financing approaches for gas utility infrastructure and evaluated their potential impacts on ratepayers in the context of California's energy transition.

II. PURPOSE AND ORGANIZATION OF TESTIMONY

Q: Have you prepared testimony submitted in this proceeding?

A: Yes. I have prepared this testimony or supervised its preparation.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to support the proposed adjustments ("Proposed Adjustments") to the Day-Ahead Ancillary Services Market ("DA A/S") as set forth in the accompanying filing letter ("Filing Letter").[1] My testimony focuses on two of the Proposed Adjustments:

1. Removing the credit adjustment to the Hourly Revenue calculation of Net Commitment-Period Compensation ("NCPC"), as specified in Tariff Section III.F.2.3.1.3, to prevent Day-Ahead External Transactions that do not have a corresponding Real-Time offer and are ineligible to receive the Forecast Energy Requirement Price ("FER Price") from receiving the equivalent in NCPC; and

[1] Capitalized terms used but not defined in these comments are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff ("Tariff") or the accompanying Filing Letter in the above-captioned docket.

2. Adjusting the threshold for the Impact Test, as specified in Tariff Section III.A.8.1.2, to have a floor of $3/MWh

Q: How is your testimony organized?

A: In Section III, I discuss and support the proposal to adjust the accounting methodology so that Day-Ahead External Transactions (also known as "imports") that are ineligible to receive the FER Price do not receive the equivalent in NCPC. In Section IV, I discuss and support the proposal to add a floor of $3/MWh to the Impact Test threshold for mitigation purposes.

III. NCPC ACCOUNTING ADJUSTMENT FOR HOURLY REVENUE

Q: By way of background, please describe NCPC and how it is calculated.

A: In ISO-NE, the NCPC payment is intended to make a resource that follows the ISO's operating instructions "no worse off" financially than the best alternative generation schedule. It ensures that resources have incentive to follow ISO dispatch instructions by paying the difference between a resource's total offer costs and its total market revenues. This difference is sometimes referred to as an "uplift" payment. Generally, NCPC is calculated as follows:

$$\text{NCPC} = \max(\text{Total Offer Costs} - \text{Total Market Revenues}, 0)$$

Q: How does the DA A/S market design factor into Day-Ahead NCPC calculations?

A: All DA A/S-related credits and DA A/S offer costs are considered in Day-Ahead NCPC calculations. On the revenue side of the equation, this includes Forecast Energy Requirement ("FER") Credits paid to resources that clear physical energy supply in the Day-Ahead Market through the FER Price.

Q: How does this work for import transactions that clear the Day-Ahead Market? Are they eligible to receive the FER Credit?

A: It depends. The DA A/S design requires that Day-Ahead External Transactions (*i.e.*, imports) have a corresponding Real-Time Supply Offer in order to be paid the FER Price and, therefore, to receive the FER Credit. A Day-Ahead cleared import without a corresponding Real-Time offer is ineligible to receive the FER Price. The FER Price is paid only to resources that help ensure a reliable next-day operating plan, which does not include an import transaction without a corresponding Real-Time supply offer.

This limitation is specified in Tariff Section III.3.2.1(a)(q)(4), which credits the FER Price to Day-Ahead cleared imports only to the extent of ("lesser of") "each MWh offered for the corresponding External Transaction in the Real-Time Energy Market." Here is the relevant current Tariff Section:

> **III.3.2.1(q)(4)**
>
> **Forecast Energy Requirement Credit for External Transaction Purchases** – Each Market Participant with an External Transaction purchase scheduled in the Day-Ahead Energy Market for which a corresponding External Transaction also has been properly submitted in the Real-Time Energy Market and submitted in the appropriate external Control Area shall be <u>credited the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(b), for the lesser of (a) each MWh of the Day-Ahead energy obligation associated with the External Transaction and (b) each MWh offered for the corresponding External Transaction in the Real-Time Energy Market.</u> [emphasis added]

Q: Does this raise an issue with respect to Day-Ahead NCPC credits?

A: Yes. The Tariff provides for NCPC purposes that the "Hourly Revenue" for an External Transaction import includes the "Day-Ahead Locational Marginal Price plus the Forecast

Energy Requirement Price," but the latter (*i.e.*, FER Price) is "subject to the conditions specified in Section III.3.2.1(q)(4)(ii)."

> **III.F.2.3.1.3. Hourly Revenue**. The Day-Ahead revenue for a pool-scheduled External Transaction import at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, <u>subject to the conditions specified in Section III.3.2.1(q)(4)(ii)</u>. For Increment Offers at an External Node, the Day-Ahead revenue at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Locational Marginal Price. [emphasis added]

As I have just testified, the "lesser of" language in Tariff Section III.3.2.1(q)(4)(ii) quoted above requires that a Day-Ahead External Transaction (*i.e.*, cleared import) must have a corresponding Real-Time supply offer to receive the FER Price. But if the Hourly Revenue calculation for NCPC does not include the FER Price, such imports without offsetting Real-Time offers may effectively receive the value of the FER Price indirectly through NCPC credits.

This outcome occurs because the FER Price is not reflected in the Hourly Revenue used in the NCPC calculation for those imports, resulting in a potential overpayment through NCPC. This can result in the cleared import without a corresponding Real-Time offer being "made whole" for the FER Price that it is not eligible to receive through a NCPC credit.

Q: Could you provide a simple example to illustrate this NCPC accounting issue?

A: Yes, here is an example the ISO provided to stakeholders at the NEPOOL Markets Committee on April 14, 2026:

Consider a 1 MW cleared Day-Ahead External Transaction import that is on the margin for energy supply:

Concept	Value ($/MWh)
DA Import Supply Offer	$60
DA LMP	$50
FER Price	$10

Assume this import has no corresponding Real-Time transaction and, therefore, is ineligible for the FER Price. The current Day-Ahead Market NCPC Credit calculation is as follows:

– Hourly Revenue = DA LMP = $50

– Hourly Cost = Supply offer = $60

– DA NCPC Credit = max(Cost – Revenue, 0) = $10

This import effectively receives the FER Price through its Day-Ahead Market NCPC Credit, even though it does not meet the eligibility requirements because it does not have a corresponding Real-Time transaction.

Q: Has this occurred in practice to your knowledge? What is the total value of FER-related Day-Ahead NCPC Credits that were paid to Day-Ahead imports ineligible for the FER Price?

While this issue has arisen in practice, the occurrences have been rare. Between March 2025 and February 2026, the NCPC accounting issue has resulted in approximately $73,000 to be paid to Day-Ahead imports ineligible for the FER Price. While the value of these payments is relatively low, the ISO believes that this issue is worth fixing as part of the Proposed Adjustments.

Q: What change is being proposed to address this issue?

A: The Proposed Adjustments include a minor change to the Day-Ahead NCPC rules such that the FER Price is considered (for accounting purposes only) as part of the "Hourly Revenue" for Day-Ahead cleared imports regardless of whether there is a corresponding Real-Time transaction.

A simple "fix" of the Tariff requires only a small adjustment to the current NCPC accounting language previously quoted above as follows:

> **III.F.2.3.1.3. Hourly Revenue**. The Day-Ahead revenue for a pool-scheduled External Transaction import at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, not subject to the credit conditions specified in Section III.3.2.1(q)(4)(ii)….

This makes the hourly revenue calculation include the FER Price and *not* be subject to the *credit* adjustment specified in Section III.3.2.1(q)(4)(ii), for NCPC accounting purposes.

In this way the FER Price or its equivalent through NCPC credits is paid only to resources that help ensure a reliable next-day operating plan, which does not include an import transaction without a corresponding Real-Time supply offer.

IV. PROPOSED FLOOR FOR THE IMPACT TEST THRESHOLD FOR MITIGATION

Q: By way of background, please describe your understanding of the mitigation framework for DA A/S.

A: The DA A/S Market includes a mitigation framework that is designed to thwart the exercise of market power through economic and physical withholding. The ISO's Internal Market Monitor ("IMM") is tasked with reviewing DA A/S offers for determining whether they need to be mitigated.

Under the ISO-NE Tariff, the IMM must review and impose mitigation of DA A/S offers to a competitive "Benchmark Level" if the offers both: (i) exceed a "Conduct Test" threshold price, which is two times (200% of) the "Expected Close-Out" cost (or at least $2/MWh) plus 1.5 times (150% of) avoidable input costs (or, if appropriate, an IMM-accepted threshold price upon consultation); and (ii) result in a violation of an "Impact Test" threshold, indicating the ability of a DA A/S offer that fails the Conduct Test to adversely impact Day-Ahead Market prices.

Q: Do the Proposed Adjustments include a proposed change to the mitigation review process for DA A/S?

A: Yes. The ISO proposes adding a floor of $3/MWh to the calculation of the Impact Test threshold for mitigation. This proposal ensures that the Impact Test threshold does not fall below $3/MWh in hours when the Day-Ahead Expected Close-Out Component ("Expected Close-Out" or "E[Close-Out]") is above $0/MWh and below $2/MWh.

Q: How does the Impact Test threshold behave under the current methodology?

A: Under the current calculation, the threshold for failing the Impact Test generally is \$3/MWh when the Expected Close-Out value is either \$0/MWh or \$2/MWh. However, when the Expected Close-Out falls between \$0/MWh and \$2/MWh, the calculation can produce a threshold that is lower than \$3/MWh, making the test generally more stringent.

Q: Why does the current methodology produce this more stringent threshold in certain conditions?

A: This outcome is an unintended feature of the Impact Test threshold calculation and arises from the interaction with the \$2/MWh minimum threshold under the Conduct Test.

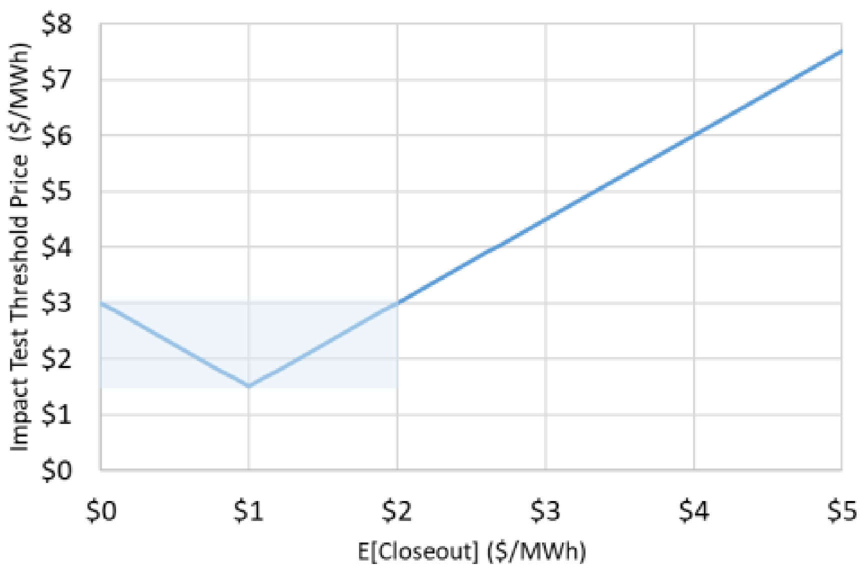
Q: Could you show graphically how this unintended feature in calculating the Impact Test threshold manifests itself?

A: Yes. First, some background may be helpful. In the call option settlement design underlying the DA A/S Market, the ISO's Gaussian Mixture Model ("GMM") produces a distribution of potential Real-Time Locational Marginal Prices ("LMPs") and calculates the Expected Close-Out for each award hour. The Expected Close-Out is a key component of competitive DA A/S offer prices, and it factors directly into the Benchmark Level (or "BL"), Conduct Test threshold (or "CTT"), and Impact Test threshold (or "ITT") parameters used in mitigation. Here are the general formulas, with outcomes graphically depicted below:

- Benchmark Level ("BL") = E[Close-Out] + Avoidable Input Cost ("AIC")
- Conduct Test threshold ("CTT") = Max(\$2, 2 x E[Closeout]) + 1.5 x AIC

- ITT = 1.5 x Median[CTT – BL]

Under the current design, the Impact Test threshold generally becomes more stringent as E[Close-Out] increases from $0/MWh.



This outcome is the result of the $2/MWh minimum for the Conduct Test threshold (*i.e.*, CTT).

– When E[Close-Out] = $0, the Impact Test Threshold (*i.e.*, “ITT”) is generally $3/MWh

– In the range $0/MWh < E[Closeout] < $2/MWh, the ITT can be less than $3/MWh, and as low as $1.50/MWh; on the figure above, this area is shaded in light blue.

This property of the Impact Test threshold calculation was not intended. As competitive costs increase as reflected in a higher Expected Close-Out, the acceptable change in clearing prices (*i.e.*, the Impact Test threshold) should not decrease.

Q: Are there any concerns if this feature of the Impact Test threshold is not addressed?

A: Yes. If left unchanged, this feature could lead to more frequent failures of the Impact Test and increased instances of mitigation, even during low-priced hours when market power is not a significant concern. This raises the risk of over-mitigation under market conditions where such intervention may not be warranted.

Q: What solution does the ISO propose to address this issue?

A: The ISO proposes applying a $3/MWh floor to the Impact Test threshold. This will prevent the Impact Test threshold for mitigation from becoming more stringent when it should not be. This targeted change is intended to address the potential for over-mitigation in hours when the Expected Close-Out is very low, and market power is not a significant concern.

Q: Does this proposal align with any external recommendations?

A: Yes. The proposed adjustment aligns with a recommendation from the External Market Monitor, Potomac Analytics, as set forth in its *2024 Assessment of the ISO-NE Electricity Markets*.

Q: Could you show how this Proposed Adjustment is reflected in the proposed Tariff redlines?

A: Yes. The proposed change to add a floor to the Impact Test threshold consists of adding (i) "higher" in place of "greater" to avoid double use of that word, and then (ii) "the greater of (a) $3/MWh and (b)" before "150% of the median difference …," which sets for the current threshold calculation, as follows:

III.A.8.1.2. Impact Test. A Day-Ahead Ancillary Services Offer with a price that fails the conduct test for Day-Ahead Ancillary Services Offer mitigation shall be evaluated against the impact test for Day-Ahead Ancillary Services Offer mitigation. A Day-Ahead Ancillary Services Offer fails the impact test for Day-Ahead Ancillary Services Offer mitigation if there is an increase in any Day-Ahead Price, as calculated pursuant to Sections III.A.8.3 or III.A.8.4, in any hour of the Operating Day and such increase is ~~greater~~ higher than the greater of (a) $3/MWh and (b) 150% of the median difference between:

(i) the threshold prices for failing the conduct test described in Section III.A.8.1.1 for all Day-Ahead Ancillary Services Offers in the hour of the Operating Day being evaluated; and

(ii) the Day-Ahead Ancillary Services Benchmark Levels as described in Section III.A.8.2 for all Day-Ahead Ancillary Services Offers in the hour of the Operating Day being evaluated.

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 16, 2026.

/s/ Anna Mazur

Anna Mazur, Analyst, ISO New England, Market Development

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied Supplied Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: "Pre-scheduling" as specified in Section III.1.9, "Scheduling" as specified in III.1.10, and "Dispatch" as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 [Reserved.]

III.1.3.2 [Reserved.]

III.1.3.3 [Reserved.]

III.1.4 Requirements for Certain Transactions.

III.1.4.1 ISO Settlement of Certain Transactions.

The ISO will settle, and act as Counterparty to, the transactions described in Section III.1.4.2 if the transactions (and their related transactions) conform to, and the transacting Market Participants comply with, the requirements specified in Section III.1.4.3.

III.1.4.2 Transactions Subject to Requirements of Section III.1.4.

Transactions that must conform to the requirements of Section III.1.4 include: Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as "Section III.1.4 Transactions," and individually as a "Section III.1.4 Transaction." Transactions that conform to the standards are referred to collectively as "Section III.1.4 Conforming Transactions," and individually as a "Section III.1.4 Conforming Transaction."

III.1.4.3 Requirements for Section III.1.4 Conforming Transactions.

(a) To qualify as a Section III.1.4 Conforming Transaction, a Section III.1.4 Transaction must constitute an exchange for an off-market transaction (a "Related Transaction"), where the Related Transaction:

(i) is not cleared or settled by the ISO as Counterparty;

(ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

(iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and

(iv) is not contingent on either party to carry out the Section III.1.4 Transaction.

(b) In addition, to qualify as a Section III.1.4 Conforming Transaction:

(i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;

(ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and

(iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.

(c) As further requirements:

(i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and

(ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

(a) The following types of Claimed Capability Audits may be performed:

(i) An Establish Claimed Capability Audit establishes the Generator Asset's ability to respond to ISO Dispatch Instructions and to maintain performance at a specified output level for a specified duration.

(ii) A Seasonal Claimed Capability Audit determines a Generator Asset's capability to perform under specified summer and winter conditions for a specified duration.

(iii) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.

(iv) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value or the Demand Response Resource's Seasonal DR Audit value.

(b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.

(d) The Claimed Capability Audit value for steam turbine assets with steam exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.

(e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

(a) An Establish Claimed Capability Audit may be performed only by a Generator Asset.

(b) The time and date of an Establish Claimed Capability Audit shall be unannounced.

(c) For a newly commercial Generator Asset:

(i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:

1. Non-intermittent daily cycle hydro;
2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
3. Intermittent Generator Assets

(ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.

(d) For Generator Assets with an Establish Claimed Capability Audit value:

(i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.

(ii) An Establish Claimed Capability Audit shall be performed within five Business Days of the date of the request.

(iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(e) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset.

(f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.

(g) To conduct an Establish Claimed Capability Audit, the ISO shall:

(i) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.

(h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

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

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

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

III.1.5.1.3. Seasonal Claimed Capability Audits.

(a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset.

(b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:

(i) Non-intermittent daily hydro; and

(ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).

(c) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset's Seasonal Claimed Capability Audit obligation.

(d) Except as provided in Section III.1.5.1.3(n) below, a summer Seasonal Claimed Capability Audit must be conducted:

(i) At least once every Capability Demonstration Year;

(ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.

(e) A winter Seasonal Claimed Capability Audit must be conducted:

(i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:

(1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.

(2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.

(ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.

(f) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset for the audit time period and submitting to the ISO operational data that meets the following requirements:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.

(g) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(h) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.

(i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2

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

(k) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;

(ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and

(iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.

(l) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;

(ii) Retain the current Seasonal Claimed Capability Audit value for the season; and

(iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.

(m) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal

Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

(n) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:

(i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(f).

(ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.

(iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.

(iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(d)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.

(v) This Section III.1.5.1.3(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

(o) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.3(j).

III.1.5.1.3.1 Seasonal DR Audits.

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

(b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.

(c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of April through November;

(d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of December through March.

(e) A Seasonal DR Audit may be performed either:

(i) At the request of a Market Participant as described in subsection (f) below; or

(ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.

(f) If a Market Participant requests a Seasonal DR Audit:

(i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.

(ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.

(iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DR Audit.

(iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.

(iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

(h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.

(i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.

(j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.

(k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.

(l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.

(m) The Seasonal DR Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.

(n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.

(o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

(a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.

(b) An ISO-Initiated Claimed Capability Audit value shall replace either the summer or winter Seasonal DR Audit value for a Demand Response Resource and shall replace both the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:

(i) The Establish Claimed Capability Audit values for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.

(ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.

(c) If for a Generator Asset a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.

(d) The audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:

(i) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit or the Demand Response Resource to its Maximum Reduction.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) For Generator Assets, begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.

(iv) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

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

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

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

III.1.5.2 ISO-Initiated Parameter Auditing.

(a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide energy or reserves.

(b) Generator audits shall be performed using the following methods for the relevant parameter:

(i) **Economic Maximum Limit**. The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.

(ii) **Manual Response Rate**. The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.

(iii) **Start-Up Time**. The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.

(iv) **Notification Time**. The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.

(v) **CLAIM10**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(vii) **Automatic Response Rate**. The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.

(viii) **Dual Fuel Capability**. A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).

(c) Demand Response Resource audits shall be performed using the following methods:

(i) **Maximum Reduction**. The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.

(ii) **Demand Response Resource Ramp Rate**. The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.

(iii) **Demand Response Resource Start-Up Time**. The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.

(iv) **Demand Response Resource Notification Time**. The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.

(v) **CLAIM10**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(d) To conduct an audit based upon historical data, the ISO shall:

(i) Obtain data through random sampling of generator or Demand Response Resource performance in response to Dispatch Instructions; or

(ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to Dispatch Instructions.

(e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.

(f) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:

(i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.

(ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five Business Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.

(g) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer or other operating parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.

(h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:

(i) The Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:

1. Provide an explanation of the discrepancy;
2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
3. Indicate the timeline for completing the restoration; and
4. Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.

(ii) The ISO shall:

1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;
2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.5.3 Reactive Capability Audits.

(a) Two types of Reactive Capability Audits may be performed:

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

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

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

(c) Unless otherwise directed by the ISO, Reactive Resources that are required to perform Reactive Capability Audits shall perform both a lagging Reactive Capability Audit and a leading Reactive Capability Audit.

(d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.

(e) The Reactive Capability Audit value of a Reactive Resource shall reflect any limitations based upon the interdependence of common elements between two or more Reactive Resources such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.

(g) Reactive Capability Audits shall be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Reactive Resource to conduct Reactive Capability Audits more often than every five years if:

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

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

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

(h) A Lead Market Participant or Transmission Owner may request a waiver of the requirement to conduct a Reactive Capability Audit for its Reactive Resource. The ISO, at its sole discretion, shall determine whether and for how long a waiver may be granted.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

III.1.6.4 ISO New England Manuals and ISO New England Administrative Procedures.

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission's regulations.

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 Transmission Constraint Penalty Factors.

In the Day-Ahead Energy Market, the Transmission Constraint Penalty Factor for an interface constraint is $10,000/MWh and the Transmission Constraint Penalty Factor for all other transmission constraints is $30,000/MWh. In the Real-Time Energy Market, the Transmission Constraint Penalty Factor for any transmission constraint is $30,000/MWh. Transmission Constraint Penalty Factors are not used in calculating Locational Marginal Prices.

III.1.7.6 Scheduling and Dispatching.

(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch. The ISO shall use a joint optimization process to serve Day-Ahead Market energy requirements and Day-Ahead Ancillary Services requirements, as described in Section III.1.10.8(a).

(b) [Reserved].

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 LMP-Based Energy Pricing.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the limitations and procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.9 Real-Time Reserve Prices.

The price paid by the ISO for the provision of Real-Time Operating Reserve in the New England Markets will reflect Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.9A Day-Ahead Ancillary Services Prices.

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

III.1.7.10 Other Transactions.

Market Participants may enter into internal bilateral transactions and External Transactions for the purchase or sale of energy or other products to or from each other or any other entity, subject to the obligations of Market Participants to make resources with a Capacity Supply Obligation available for dispatch by the ISO. External Transactions that contemplate the physical transfer of energy or obligations to or from a Market Participant shall be reported to and coordinated with the ISO in accordance with this Market Rule 1 and the ISO New England Manuals.

III.1.7.11 Seasonal Claimed Capability of a Generating Capacity Resource.

(a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.

(b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.

(c) The Seasonal Claimed Capability of a Generator Asset is:

(i) Based upon review of historical data for non-intermittent daily cycle hydro.

(ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.

(iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:

a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.

b. For a Generator Asset that is off-line and not available for commitment shall be zero.

c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.

(iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

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

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

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

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

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and zonal Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 Ramping.

A Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to potential referral under Section III.A.19.

III.1.7.19 Real-Time Reserve Designation.

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

III.1.7.19.1 Eligibility.

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

(1) The Resource must be a Dispatchable Resource located within the metered boundaries of the New England Control Area and capable of receiving and responding to electronic Dispatch Instructions.

(2) The Resource must not be part of the first contingency supply loss.

(3) The Resource must not be designated as constrained by transmission limitations.

(4) The Resource's Operating Reserve, if activated, must be sustainable for at least one hour from the time of activation. (This eligibility requirement does not affect a Resource's obligation to follow Dispatch Instructions, even after one hour from the time of activation.)

(5) The Resource must comply with the applicable standards and requirements for provision and dispatch of Operating Reserve as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19.2 Calculation of Real-Time Reserve Designation.

III.1.7.19.2.1 Generator Assets.

III.1.7.19.2.1.1 On-line Generator Assets.

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

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

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

(c) **Thirty-Minute Operating Reserve.** For an on-line Generator Asset, Thirty-Minute Operating Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within thirty minutes given its Manual Response Rate (and in no case greater than its Economic Maximum Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (b) above.

III.1.7.19.2.1.2 Off-line Generator Assets.

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

(a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.

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

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

III.1.7.19.2.2 Dispatchable Asset Related Demand.

III.1.7.19.2.2.1 Storage DARDs.

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

(b) **Ten-Minute Non-Spinning Reserve.** For a Storage DARD, Ten-Minute Non-Spinning Reserve shall be zero.

(c) **Thirty-Minute Operating Reserve.** For a Storage DARD, Thirty-Minute Operating Reserve shall be zero.

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

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

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

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

III.1.7.19.2.3 Demand Response Resources.

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

III.1.7.19.2.3.1 Dispatched.

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

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

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

III.1.7.19.2.3.2 Non-Dispatched.

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

(a) **Ten-Minute Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Spinning Reserve shall be zero.

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

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

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO Resources that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output, consumption, or demand reduction levels of Generator Assets, DARDs, or Demand Response Resources, change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, equipment is operated with control equipment functioning as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands required by the ISO New England Operating Documents, including but not limited to the Market Participant's ability to procure fuel and physical limitations that could reduce Resource output or demand reduction capability for the pertinent Operating Day.

III.1.7.21 SATOA Participation in Markets: A Node will be established for each SATOA. A Market Participant's market activity, transactions, and actions taken at a SATOA's Node and a SATOA's participation in the New England Markets shall be limited to those necessary to consume or inject energy from or to PTF for any period, magnitude, and duration identified as necessary to: (1) address the applicable system needs or provide the transmission function for which the SATOA was selected as the preferred solution; or (2) as specified in the ISO New England Operating Documents, avoid or mitigate Load Shedding after all available Dispatchable Resources that can effectively provide relief to avoid or mitigate the Load Shedding have been dispatched.

III.1.8 Day-Ahead Ancillary Services and Forecast Energy Requirement.

III.1.8.1 Day-Ahead Ancillary Services Offers.

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

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

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

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

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

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

III.1.8.2 Day-Ahead Ancillary Services Strike Price.

(a) For each hour of the Operating Day, the ISO shall specify the Day-Ahead Ancillary Services Strike Price in $/MWh. The value of the Day-Ahead Ancillary Services Strike Price represents an amount that is the greater of the values calculated in accordance with subsections (1) and (2) below:

(1) the greater of (i) $10/MWh greater than a forecast of the expected hourly Real-Time Hub Price for such hour of the Operating Day and (ii) zero; and

~~(1)~~(2) a floor value derived in accordance with subsection (c) below.

~~(a)~~(b) The ~~forecast used to determine the Day-Ahead Ancillary Services Strike Price~~ value calculated in subsection (a)(1) above shall be based on a publicly-available forecasting algorithm developed by the ISO. The ISO shall describe the publicly-available forecasting algorithm to Market Participants and shall periodically review and assess the efficacy of the forecasting algorithm. The ISO shall notify stakeholders of any potential revisions to the ISO's forecasting algorithm prior to implementing such revisions.

(c) The floor value in subsection (a)(2) above shall be determined daily based on the marginal cost of supplying energy by an efficient, distillate-fired combustion turbine generator, reflecting regional emissions costs and the lowest-priced distillate fuel available. The ISO shall describe to Market Participants the heat rate, emissions cost, and fuel prices that it uses to determine the value in subsection (a)(2)~~In the event that the ISO is not able to utilize the ISO-developed forecasting algorithm described in subsection (b) above due to hardware, software, or telecommunications problems, human error, or exigent circumstances not contemplated by this market rule, the ISO shall determine the Day-Ahead Ancillary~~

~~Services Strike Price using the best forecast available and shall disclose the use of such substitute forecast to Market Participants as soon as practicable~~.

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

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

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

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

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

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

III.1.8.4 Forecast Energy Requirement Demand Quantity.
For each hour of the Operating Day, the Forecast Energy Requirement Demand Quantity shall be: ~~equal to~~

(1) the ISO forecast for the total load in the New England Control Area produced pursuant to Section III.1.10.1A(h) of this Market Rule 1, less

~~(1)~~(2) the greater of (i) the forecast of front-of-the-meter dispatchable wind and solar resources' total real-time energy supply, as adjusted for any expected operating conditions, less the total energy supply and ancillary services from such resources forecast to clear in the Day-Ahead Market and (ii) zero.

III.1.9 Pre-scheduling.

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

III.1.9.1.1 Cost Verification of Resource Offers.

The incremental energy values of Supply Offers and Demand Response Resources above $1,000/MWh for any Resource other than an External Resource are subject to the following cost verification requirements. Unless expressly stated otherwise, cost verification is utilized in all pricing, commitment, dispatch and settlement determinations. For purposes of the following requirements, Reference Levels are calculated using the procedures in Section III.A.7.5 for calculating cost-based Reference Levels.

(a) If the incremental energy value of a Resource's offer is greater than the incremental energy Reference Level value of the Resource, then the incremental energy value in the offer is replaced with the greater of the Reference Level for incremental energy or $1,000/MWh.

(b) For purposes of the price calculations in Sections III.2.5 and III.2.7A, if the adjusted offer calculated under Section III.2.4 for a Rapid Response Pricing Asset is greater than $1,000/MWh (after the incremental energy value is evaluated under Section III.1.9.1.1(a) above), then verification will be performed as follows using a Reference Level value calculated with the adjusted offer formulas specified in Section III.2.4.

(i) If the Reference Level value is less than or equal to $1,000/MWh, then the adjusted offer for the Resource is set at $1,000/MWh;

(ii) If the Reference Level value is greater than $1,000/MWh, then the adjusted offer for the Resource is set at the lower of the Reference Level value and the adjusted offer.

III.1.9.1.2 Offer and Bid Caps.

(a) For purposes of the price calculations described in Section III.2 and for purposes of scheduling a Resource in the Day-Ahead Energy Market in accordance with Section III.1.7.6 following the commitment of the Resource, the incremental energy value of an offer is capped at $2,000/MWh.

(b) Demand Bids shall not specify a bid price below the Energy Offer Floor or above the Demand Bid Cap.

(c) Supply Offers and Demand Reduction Offers shall not specify an offer price (for incremental energy) below the Energy Offer Floor.

(d) External Transactions shall not specify a price below the External Transaction Floor or above the External Transaction Cap.

(e) Increment Offers and Decrement Bids shall not specify an offer or bid price below the Energy Offer Floor or above the Virtual Cap.

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each Generator Asset as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline and shall remain in effect unless otherwise modified in accordance with Section III.1.10.9. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement the Day-Ahead Market and a Real-Time Energy Market.

(b) The Day-Ahead Market shall enable Market Participants to purchase and sell energy and sell ancillary services through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level.

Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of Generator Assets or Demand Response Resources with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers or Demand Reduction Offers.

III.1.10.1A Energy and Day-Ahead Ancillary Services Market Scheduling.

Market Participants may submit offers and bids in the Day-Ahead Market until 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) **Locational Demand Bids –** Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the applicable Day-Ahead Price, (ii) hourly schedules for Resources Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the Demand Bid Cap and Virtual Cap.

(b) **External Transactions –** All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) In the Day-Ahead Energy Market, the offer prices for all Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) In the Day-Ahead Energy Market, the offer prices for all Self-Scheduled External Transaction sales at the applicable External Node shall be set equal to the External Transaction Cap;

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(c) **Generator Asset Supply Offers –** Market Participants selling into the New England Markets from Generator Assets may submit Supply Offers for the supply of energy for the following Operating Day.

Such Supply Offers:

(i) Shall specify the Resource and Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) If based on energy from a Generator Asset internal to the New England Control Area, may specify, for Supply Offers, a Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee may vary on an hourly basis;

(iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual-fuel Generator Assets in Section III.A.3 of Appendix A;

(iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;

(v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource (except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and

(vi) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.

(d) DARD Demand Bids – Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

(i) Shall specify the Dispatchable Asset Related Demand and Blocks (price and Energy quantity pairs) for each hour of the Operating Day for each Dispatchable Asset Related Demand offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) Shall constitute an offer to submit the Dispatchable Asset Related Demand to the ISO for commitment and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes, including to the Maximum Consumption Limit and Minimum Consumption Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource;

(iii) Shall specify a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit; and

(iv) Shall, in the case of a Demand Bid from a Storage DARD, also meet the requirements specified in Section III.1.10.6.

(e) **Demand Response Resource Demand Reduction Offers –** Market Participants selling into the New England Markets from Demand Response Resources may submit Demand Reduction Offers for the supply of energy for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource to the ISO for commitment and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The prices and demand reduction quantities may vary on an hourly basis.

(ii) Shall not specify a price that is below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

(iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.

(iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.

(v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.

(vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets.

(vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource.

(f) **Demand Reduction Threshold Price –** The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data <u>(excluding Coordinated External Transactions)</u> for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

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

(b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.

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

(d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th}X - \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the month preceding the Demand Reduction Threshold Price's effective date.

(g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction Offer, or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer, a Demand Reduction Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) **Load Estimate** – The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) **Prorated Supply** – In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions are not used in determining the amount of energy (MW) in each marginal Supply Offer or Demand Reduction Offer to be cleared on a pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions.

(j) **Prorated Demand** – In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids, Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) **Virtuals** – All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

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

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers, Demand Reduction Offers, or Demand Bids in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as Generator Assets, DARDs or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume energy in the Real-Time dispatch unless the schedules for such Resources are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy supply or consumption, ancillary services, and related services, Start-Up Fees, No-Load Fees, Interruption Cost and the specified operating characteristics, offered by Market Participants.

(b) The ISO shall optimize the dispatch of energy and ancillary services from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such

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

(c) Market Participants offering energy from facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled shall be governed by the following principles and procedures. The minimum duration of a Self-Schedule for a Generator Asset or DARD shall not result in the Generator Asset or DARD operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer. A DARD that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid. A Demand Response Resource shall not be Self-Scheduled.

III.1.10.4 External Resources.

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

III.1.10.5 Dispatchable Asset Related Demand.

(a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.

(b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:

(i) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand's ability to respond to Dispatch Instructions and the expected return date from the outage;

(ii) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;

(iii) abide by the ISO maintenance coordination procedures; and

(iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

III.1.10.6 Electric Storage

A storage facility is a facility that is capable of receiving electricity and storing the energy for later injection of electricity into the grid. A storage facility may participate in the New England Markets as described below.

(a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:

(i) comprise one or more storage facilities at the same point of interconnection;

(ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;

(iii) be directly metered;

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

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

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

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

(viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

(b) A storage facility that satisfies the requirements of this subsection (b) may participate in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility; and

(ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and

(iii) be issued Dispatch Instructions in a manner that ensures the facility is not required to consume and inject simultaneously.

(c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility;

(ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;

(iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;

(iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;

(v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time, Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;

(vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;

(vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and

(viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).

(d) In clearing the Day-Ahead Energy Market, the ISO will respect Electric Storage Facility Initial State of Charge, Round Trip Efficiency, Maximum State of Charge, and Minimum State of Charge.

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

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

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

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

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

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

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

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

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

(g) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.

(h) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.

(i) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)

(j) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.

(k) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

III.1.10.7 External Transactions.

The provisions of this Section III.1.10.7 do not apply to Coordinated External Transactions.

(a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.

(b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, require a change in schedule.

(d) External Transactions submitted to the Real-Time Energy Market must contain the associated e-Tag ID and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) [Reserved.]

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone, as determined in accordance with Section III.12.4, that experienced price separation in the Annual Capacity Auction as determined in accordance with Section III.15.4.2.2(j) of Market Rule 1;

(2) The External Transaction is directly associated with an Export Offer Segment that did not receive a Capacity Supply Obligation in the Annual Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the unobligated Export Offer Segment;

(3) The External Node associated with the unobligated Export Offer Segment is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(ii) Annual Capacity Auction Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Offer Segment that did not receive a Capacity Supply Obligation in the Annual Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the unobligated Export Offer Segment;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Offer Segment is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward or Annual Capacity Auction in the direction of the export;

(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and Annual Capacity Auction Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and Annual Capacity Auction Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and Annual Capacity Auction Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.7.A Coordinated Transaction Scheduling.

The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An

Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15-minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated e-Tag ID at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, permit the transaction to be scheduled.

III.1.10.8 Scheduling Considerations.

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

In making the determination specified in this subsection (a), the ISO shall take into account, as applicable: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for ancillary services; (vi) the operational capabilities of any Resource to adjust the output, consumption, or demand reduction within the operating characteristics and parameters specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, or Demand Bid and any audited values of such operating characteristics and parameters; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination.

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

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

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

~~(2)~~(3) The Generator Asset or Demand Response Resource is, for the applicable hour, either scheduled for energy in the Day-Ahead Energy Market or is a Fast Start Generator or Fast Start Demand Response Resource.

~~(3)~~(4) The Generator Asset or Demand Response Resource is not designated as constrained by transmission limitations, as described in Section III.1.7.19.1(3).

(b) Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead energy and ancillary services schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Market cannot be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors. The ISO shall use its best efforts to determine the least-cost means to satisfy any remaining reliability requirements of the New England Control Area for the Operating Day.

(d) Market Participants shall pay and be paid for the quantities of energy and ancillary services scheduled in the Day-Ahead Market based upon applicable Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Resources and to direct that schedules be changed to address an actual or potential Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) During the Re-Offer Period, Market Participants may submit revisions to the price of priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis or request to reduce the quantity of a priced External Transaction. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(b) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

(i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual-fuel Generator Assets), and the quantity and price pairs of its Blocks may be modified.

(ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.

(e) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit. A Market Participant may not request to Self-Schedule a Demand Response Resource. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.

(f) During the Operating Day, in the event that in a given hour a Market Participant seeks to modify a Supply Offer or Demand Bid after the deadline for modifications specified in Section III.1.10.9(c), then:

(i) the Market Participant may request that a Generator Asset be dispatched above its Economic Minimum Limit at a specified output. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Generator Asset will be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

(ii) the Market Participant may request that a Dispatchable Asset Related Demand be dispatched above its Minimum Consumption Limit at a specified value. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Dispatchable Asset Related Demand will be dispatched at or above the requested amount for the hour in question.

(g) During the Operating Day, in any interval in which a Generator Asset is providing Regulation, the upper limit of its energy dispatch range shall be reduced by the amount of Regulation Capacity, and the lower limit of its energy dispatch range shall be increased by the amount of Regulation Capacity. Any such adjustment shall not affect the Real-Time Reserve Designation.

(h) During the Operating Day, in any interval in which a Continuous Storage ATRR is providing Regulation, the upper limit of the associated Generator Asset's energy dispatch range shall be reduced by the Regulation High Limit, and the associated DARD's consumption dispatch range shall be reduced by the Regulation Low Limit. Any such adjustment shall not affect the Real-Time Reserve Designation.

(i) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output or Consumption and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) to minimize the cost of supplying the energy, reserves, and other services required by the

Market Participants and the operation of the New England Control Area; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Dispatchable Resources.

With the exception of Settlement Only Resources, Generator Assets that meet the size criteria to be Settlement Only Resources, External Transactions, and nuclear-powered Resources, all Resources must be Dispatchable Resources in the Energy Market and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.
2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources in the Energy Market are subject to the following requirements:

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Dispatchable Resources and the designation of Real-Time Operating Reserve to Dispatchable Resources, including the dispatchable portion of Resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources. Each Market Participant shall ensure that the entity controlling a Dispatchable Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.

(e) Settlement Only Resources are not eligible to be DNE Dispatchable Generators.

Wind, solar, and hydro Intermittent Power Resources that are not Settlement Only Resources are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:

(i) A Market Participant may elect, but is not required, to have a wind, solar, or hydro Intermittent Power Resource that is less than 5 MW and is connected through transmission facilities rated at less than 115 kV be dispatched as a DNE Dispatchable Generator.

(ii) A Market Participant with a hydro Intermittent Power Resource that is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range may elect to have that resource dispatched as a DDP Dispatchable Resource.

(f) The ISO may request that dual-fuel Generator Assets that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fuel Generator Assets that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fuel Generator Assets that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.

If the ISO anticipates or declares an Emergency Condition, all External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

III.1.11.5 Dispatchability Requirements for Intermittent Power Resources.

(a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.

(b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. Redeclarations must be updated throughout the Operating Day to reflect actual operating capabilities.

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

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

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

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

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

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

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

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

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

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

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

III.1.11.6 Non-Dispatchable Resources.

Non-Dispatchable Resources are subject to the following requirements:

(a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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

III.A.1.1. Mission Statement.

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

III.A.1.2. Structure and Oversight.

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

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

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this ***Appendix A***.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this ***Appendix A***, the provisions of ***Appendix A*** shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III. A.17.3 are also part of the Participants Agreement and cannot be modified in either ***Appendix A*** or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

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

III.A.2. Functions of the Market Monitor.

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

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

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this ***Appendix A***). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

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

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

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

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

(a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this ***Appendix A***, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

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

(d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this ***Appendix A,*** provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

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

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

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

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

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

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

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

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

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

(d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this ***Appendix A.***

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

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

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

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

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

(i) *Economic withholding*, that is, submitting a Supply Offer or Day-Ahead Ancillary Services Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 or Section III.A.8 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.

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

(iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this ***Appendix A***.

(iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this ***Appendix A.***

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

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

(i) Anti-competitive gaming of Resources;
(ii) Conduct and market outcomes that are inconsistent with competitive markets;
(iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;
(iv) Actions in one market that affect price in another market;
(v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this ***Appendix A***, interfere with efficient market operation, both short-run and long-run; and
(vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this ***Appendix A***. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this ***Appendix A.*** If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

(l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.8, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

(m) Evaluate physical withholding of Supply Offers and Day-Ahead Ancillary Services Offers in accordance with Section III.A.4 below for referral to the Commission.

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

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

III.A.2.4.1. Purpose.

The mitigation measures set forth in this ***Appendix A*** for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule l (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this ***Appendix A***. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this ***Appendix A***, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential referral under Section III.A.19.

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

To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.8, III.A.10, III.A.11, III.A.21, III.A.22, and III.A.24 below.

III.A.2.4.3. Applicability.

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

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

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

III.A.2.4.5. Duration of Mitigation.

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

III.A.2.4.6. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied pursuant to Sections III.A.5 or III.A.8 due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the Operating Day associated with the Supply Offer or Day-Ahead Ancillary Services Offer to which such mitigation applied. The ISO shall correct the error as part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer or Day-Ahead Ancillary Services Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.2.4.7. Delay of Day-Ahead Market Due to Mitigation Process.

The posting of the Day-Ahead Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources and Benchmark Levels for Day-Ahead Ancillary Services Offers; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 and Day-Ahead Ancillary Services Benchmark Levels under Section III.A.8.2 for that Market Participant**.** In order for the Internal Market Monitor to revise Reference Levels or Day-Ahead Ancillary Services Benchmark Levels, or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 or Section III.A.8.1.1 for an Operating Day or hour for which the offer is submitted, all cost data and other verifiable supporting information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level or Day-Ahead Ancillary Services Benchmark Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

(a) If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(c), believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. If the Internal Market Monitor determines that there is an increased cost related to a Supply Offer, the Internal Market Monitor will either update the Reference Level or treat the offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted.

(b) If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(c), believes will cause the expected close-out costs or input costs associated with a Day-Ahead Ancillary Services Offer to exceed the level that would violate the conduct test specified in Section III.A.8.1.1 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. If the Internal Market Monitor determines that there is an increased cost related to a Day-Ahead Ancillary Services Offer, the Internal Market Monitor will either update one or both of the components of the Day-Ahead Ancillary Services Benchmark Level, as applicable, or treat the offer as not violating the conduct test specified in Section III.A.8.1.1 for the hour for which the offer is submitted.

(c) If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change.

(d) Any request pursuant to this Section III.A.3.1 must be submitted to the Internal Market Monitor with all supporting cost data and other verifiable supporting information. In order for a request pursuant to this Section III.A.3.1 to be considered for the purposes of the Day-Ahead Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Market. In order for a request to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. A request submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this ***Appendix A*** for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels and Day-Ahead Ancillary Services Benchmark Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels and both components of the Day-Ahead Ancillary Services Benchmark Levels applicable to that Market Participant's Supply Offers and any Day-Ahead Ancillary Services Offers through the MUI. Updated Reference Levels and components of the Day-Ahead Ancillary Services Benchmark Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels or the components of the Day-Ahead Ancillary Services Benchmark Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer and the Day-Ahead Ancillary Services Avoidable Input Cost for any associated Day-Ahead Ancillary Services Offers, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer and the Day-Ahead Ancillary Services Avoidable Input Cost for any associated Day-Ahead Ancillary Services Offers. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change, and for any associated Day-Ahead Ancillary Services Offers entered in the Day-Ahead Ancillary Services Market. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer and the Day-Ahead Ancillary Services Avoidable Input Cost for any associated Day-Ahead Ancillary Services Offers, the fuel price must be submitted prior to the applicable offer deadline.

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer and to cover an award consistent with any associated Day-Ahead Ancillary Services Offers, exclusive of resource-specific transportation costs. Modifications to Reference Levels or Day-Ahead Ancillary Services Avoidable Input Costs based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer and any Day-Ahead Ancillary Services Avoidable Input Cost or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer and any Day-Ahead Ancillary Services Avoidable Input Cost plus $2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer and any associated Day-Ahead Ancillary Services Offers, as of the time that the Supply Offer and any associated Day-Ahead Ancillary Services Offers were submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels and the components of Day-Ahead Ancillary Services Benchmark Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2
2 or more	6

III.A.4. Physical Withholding.

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

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

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

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

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

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

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

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

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

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

(c) As applied to the Day-Ahead Ancillary Services Market, withholding that exceeds the greater of 20% or 100 MW of the total Day-Ahead Ancillary Services capability of a Market Participant's Resources; or

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

III.A.4.2.2. Adjustment to Generating Capacity.

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

III.A.4.2.3. Withholding of Transmission.

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

III.A.4.2.4. Resources in Congestion Areas.

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

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Sections III.A.5 or III.A.8, as appropriate.

III.A.5. Supply Offer Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

(a) all Supply Offer parameters shall be reviewed for economic withholding;

(b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;

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

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

(a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;

(b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

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III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

(i) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;

(j) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than $25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated by substituting Supply Offers of Resources that have failed the applicable conduct test with the lesser of the Reference Level and Supply Offer. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

(a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using the lesser of their Reference Levels and Supply Offer for Resources that have failed the conduct test, or;

(b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using the lesser of their Reference Levels and Supply Offer for Resources that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Supply Offer Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or $100/MWh, whichever is lower. Offer block prices below $25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or $100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to the lesser of their Reference Levels and Supply Offer, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or $25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or $25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to the lesser of their Reference Levels and Supply Offer, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to the lesser their of Reference Levels and Supply Offer, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then the financial parameters of its Supply Offer are set the lesser of to their Reference Levels and Supply Offer, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then the financial parameters of its Supply Offer are set to the lesser of their Reference Levels and Supply Offer, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

i. local first contingency;
ii. local second contingency;
iii. VAR or voltage;
iv. distribution (Special Constraint Resource Service);

v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to the lesser of their Reference Levels and Supply Offer. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then the financial parameters of its Supply Offer are set to the lesser of their Reference Level or Supply Offer, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then the financial parameters of its Supply Offer shall be set to the lesser of their Reference Levels and Supply Offer, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

(a) If the Resource is starting from an offline state, the Start-Up Fee;
(b) The sum of the No Load Fees for the Commitment Period; and
(c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 "General Threshold Energy Mitigation" or III.A.5.5.2 "Constrained Area Energy Mitigation" is in effect for the following duration:

(a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:

    i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,
    ii. for constrained area energy mitigation, the Resource is not located within a constrained area.

(b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 "Constrained Area Energy Mitigation"), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 "Manual Dispatch Energy Mitigation" is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource's Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 "General Threshold Commitment Mitigation", III.A.5.5.5 "Constrained Area Commitment Mitigation", or III.A.5.5.6 "Reliability Commitment Mitigation" is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 "Start-Up Fee and No-Load Fee Mitigation" is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

Market Participants are responsible for providing the Internal Market Monitor with all the information and data necessary for the Internal Market Monitor to calculate up-to-date Reference Levels for each of a Market Participant's Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

(a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.

(b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.
(c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Offers.
The Reference Levels for Start-Up Fees, No-Load Fees, Interruption Costs and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.
The Internal Market Monitor will calculate a Reference Level for each offer block of an offer according to the following hierarchy, under which the first method that can be calculated is used:

(a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
(b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
(c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.
In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

(a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.
(b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
(c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
(d) For any Operating Day for which, during the previous 90 days:
  (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
  (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of

economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.

(e) When in any hour the incremental energy parameter of an offer, including adjusted offers pursuant to Section III.2.4, is greater than $1,000/MWh.

For the purposes of this subsection:

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

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

iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.

iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.

(e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.

(f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:

(i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,

(ii) No-Load Fee or its corresponding fuel blends,

(iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,

(iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and

(v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

(a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".

(b) Costs must be documented.

(c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible. All cost estimates, including opportunity cost estimates, must be quantified and analytically supported.

(d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.

(e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

i. Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and

ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy/Reduction:
(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

(a) emissions limits;
(b) water storage limits;
(c) other operating permits that limit production of energy; and
(d) reducing electricity consumption.

No-Load:
(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price)

+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up/Interruption:
(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. Day-Ahead Ancillary Services Offer Mitigation.

Day-Ahead Ancillary Services Offers will be evaluated for economic withholding in the Day-Ahead Market and mitigated as described in this Section III.A.8.

III.A.8.1. Conduct and Impact Test.

III.A.8.1.1. Conduct Test.

A Day-Ahead Ancillary Services Offer price fails the conduct test for Day-Ahead Ancillary Services Offer mitigation in a given hour if such price exceeds an amount greater than the sum of (i) the greater of $2/MWh and 200% of the Day-Ahead Ancillary Services Expected Close-Out Component as described in Section III.A.8.2.1; and (ii) 150% of the Day-Ahead Ancillary Services Avoidable Input Cost as described in Section III.A.8.2.2.

III.A.8.1.2. Impact Test.

A Day-Ahead Ancillary Services Offer with a price that fails the conduct test for Day-Ahead Ancillary Services Offer mitigation shall be evaluated against the impact test for Day-Ahead Ancillary Services Offer mitigation. A Day-Ahead Ancillary Services Offer fails the impact test for Day-Ahead Ancillary Services Offer mitigation if there is an increase in any Day-Ahead Price, as calculated pursuant to Sections III.A.8.3 or III.A.8.4, in any hour of the Operating Day and such increase is ~~greater~~ higher than the greater of (a) $3/MWh and (b) 150% of the median difference between:

(i) the threshold prices for failing the conduct test described in Section III.A.8.1.1 for all Day-Ahead Ancillary Services Offers in the hour of the Operating Day being evaluated; and

(ii) the Day-Ahead Ancillary Services Benchmark Levels as described in Section III.A.8.2 for all Day-Ahead Ancillary Services Offers in the hour of the Operating Day being evaluated.

III.A.8.1.3. Consequence of Failing Both Conduct and Impact Test.

If any Day-Ahead Ancillary Services Offer with a price that fails the Day-Ahead Ancillary Services Offer conduct test fails the impact test, then all Day-Ahead Ancillary Services Offer prices that failed the conduct test in the hour being evaluated shall be set to the applicable Day-Ahead Ancillary Services Benchmark Level.

III.A.8.2. Day-Ahead Ancillary Services Benchmark Levels.

A resource's Day-Ahead Ancillary Services Benchmark Level for the hour associated with the resource's Day-Ahead Ancillary Services Offer is the sum of the Day-Ahead Ancillary Services Expected Close-Out Component and the resource's Day-Ahead Ancillary Services Avoidable Input Cost for such hour.

III.A.8.2.1. Day-Ahead Ancillary Services Expected Close-Out Component.

The Day-Ahead Ancillary Services Expected Close-Out Component for a given hour is the lesser of the following:

(a) the expected value of the greater of (i) the hourly Real-Time Hub Price less the hourly Day-Ahead Ancillary Services Strike Price and (ii) zero; and

(b) the historical average of the estimated likelihood that the Real-Time Hub Price will be equal to or less than its expected value, multiplied by the greater of $100/MWh and the expected hourly Real-Time Hub Price.

III.A.8.2.2. Day-Ahead Ancillary Services Avoidable Input Cost.

For purposes of calculating Day-Ahead Ancillary Services Benchmark Levels and conducting the conduct test described in Section III.A.8.1.1, Day-Ahead Ancillary Services Avoidable Input Costs shall be determined as follows:

(a) For a Generator Asset with natural gas as its only fuel type, or a dual-fuel Generator Asset that has specified natural gas as its fuel type in its Supply Offer for the hour associated with the Day-Ahead Ancillary Services Offer, the Day-Ahead Ancillary Services Avoidable Input Cost shall be calculated based on the asset's average heat rate and the expected price of natural gas to cover the Day-Ahead Ancillary Services award, adjusted for the expected hourly Real-Time Hub Price.

(b) For an asset that is an Electric Storage Facility, the Day-Ahead Ancillary Services Avoidable Input Cost shall be calculated based on the expected cost of charging energy to cover the Day-Ahead Ancillary Services award, adjusted for the expected Real-Time revenue associated with that charged energy during the Operating Day.

(c) For asset types other than those described in subsections (a) and (b), the Day-Ahead Ancillary Services Avoidable Input Cost shall be zero.

(d) The Day-Ahead Ancillary Services Avoidable Input Cost shall in no case be less than zero.

III.A.8.2.3. Cost Information Provided Through Consultation.

In performing the Day-Ahead Ancillary Services Benchmark Level calculations in this Section III.A.8.2, the Internal Market Monitor shall take into account, as appropriate, information provided by the Market Participant through the consultation process described in Section III.A.3. The criteria enumerated in (a) through (e) of Section III.A.7.5 shall apply to estimates of costs when performing Day-Ahead Ancillary Services Benchmark Level calculations.

III.A.8.3. Calculation of Impact to the Day-Ahead Ancillary Services Market.

For the purpose of determining any increase in Day-Ahead Ancillary Services prices pursuant to Section III.A.8.1.2, the Day-Ahead Ancillary Service impact test shall calculate the difference between two Day-Ahead Ancillary Service prices for each product in each hour. The first price shall be calculated based on a run of the Day-Ahead Market using all Day-Ahead offers and bids as submitted. The second price shall be calculated based on a second run of the Day-Ahead Market substituting Day-Ahead Ancillary Services Benchmark Levels for the Day-Ahead Ancillary Services Offer prices that have failed the Day-Ahead Ancillary Services conduct test.

III.A.8.4. Calculation of Impact to the Day-Ahead Energy Market.

For the purpose of determining any increase in Day-Ahead energy prices pursuant to Section III.A.8.1.2, the Day-Ahead Ancillary Service impact test shall calculate the difference between two prices in each hour. The first price shall be the Hub Price calculated based on a run of the Day-Ahead Market using all Day-Ahead offers and bids as submitted. The second price shall be the Hub Price calculated based on a second run of the Day-Ahead Market substituting Day-Ahead Ancillary Services Benchmark Levels for the Day-Ahead Ancillary Services Offer prices that have failed the Day-Ahead Ancillary Services conduct test.

III.A.8.5. Duration of Day-Ahead Ancillary Services Offer Mitigation.

Any mitigation imposed on a Day-Ahead Ancillary Services Offer pursuant to this Section III.A.8 is in effect only for the hour in which the Day-Ahead Ancillary Services Offer has a price that fails the conduct test in Section III.A.8.1.1.

III.A.9. Regulation.

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

III.A.10. Demand Bids.

The Internal Market Monitor will monitor the Energy Market as outlined below:

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

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

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

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

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

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

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

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

III.A.11.3. Mitigation Measures.

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

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

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

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

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

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

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

III.A.12. Cap on FTR Revenues.

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

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Capacity Market.

In accordance with the following provisions of this ***Appendix A***, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Capacity Market and the exit of certain resources, in the form of deactivations, from the Capacity Market. Sections III.A.21, III.A.22, III.A.23, and III.A.24 of this ***Appendix A*** specify the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Capacity Market.

Sections III.13.4 and III.15.5 of Market Rule 1 address reconfiguration auctions in the Capacity Market. As addressed in Sections III.13.4.2 and III.15.5.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility and Resource Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities and is supplemented by Operating Procedure No. 5, which addresses outage scheduling for transmission facilities and Resources. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners and Resource Lead Market Participants. The Internal Market Monitor shall have the right to request that each Transmission Owner or Resource Lead Market Participant provide information to the Internal Market Monitor concerning the Transmission Owner or Resource Lead Market Participant's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner or Resource Lead Market Participant shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this ***Appendix A***. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.

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

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Cost Recovery Request Following Capping.

If as a result of an offer being capped under Section III.1.9, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was capped, the Market Participant may, within 20 days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit an additional cost recovery request to the Internal Market Monitor.

A request under this Section III.A.15 may seek recovery of additional costs incurred for the duration of the period of time for which the Resource was operated at the cap.

III.A.15.1.1. Timing and Contents of Request.

Within 20 days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant requesting additional cost recovery under this Section III.A.15.1 shall submit to the Internal Market Monitor a request in writing detailing: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data, documentation and calculations for those costs; and (ii) an explanation of why the actual costs of operating the Resource exceeded the capped costs.

III.A.15.1.2. Review by Internal Market Monitor.

To evaluate a Market Participant's request, the Internal Market Monitor shall use the data, calculations and explanations provided by the Market Participant to verify the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, using the same standards and methodologies the Internal Market Monitor uses to evaluate requests to update Reference Levels under Section III.A.3 of Appendix A. To the extent the Market Participant's request warrants additional cost recovery, the Internal Market Monitor shall reflect that adjustment in the Resource's Reference Levels for the period covered by the request. The ISO shall then re-apply the cost verification and capping formulas in Section III.1.9 using the updated Reference Levels to re-calculate the adjustments to the Market

Participant's offers required thereunder, and then shall calculate additional cost recovery using the adjusted offer values.

Within 20 days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the Market Participant's request, detailing (i) the extent to which it agrees with the request with supporting explanation, and (ii) a calculation of the additional cost recovery. Changes to credits and charges resulting from an additional cost recovery request shall be included in the Data Reconciliation Process.

III.A.15.1.3. Cost Allocation.

The ISO shall allocate charges to Market Participants for payment of any additional cost recovery granted under this Section III.A.15.1 in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.15.2. Section 205 Filing Right.

(i) If either

(a) as a result of mitigation applied to a Resource under this ***Appendix A*** for all or part of one or more Operating Days, or

(b) in the absence of mitigation, as a result of a request under Section III.A.15.1 being denied in whole or in part,

a Market Participant believes that it will not recover the fuel, variable operating and maintenance costs, or Day-Ahead Ancillary Services close-out or input costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was mitigated or the Section III.A.15.1 request was denied, the Market Participant may submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. For filings to address cost recovery under Section III.A.15.2(i)(a), the filing must be made within sixty days of receipt of the first Invoice issued containing credits or charges for the applicable Operating Day. For filings to address cost recovery under Section III.A.15.2(i)(b), the filing must be made within sixty days of receipt of the first Invoice issued that reflects the denied request for additional cost recovery under Section III.A.15.1.

(ii) A request under this Section III.A.15.2 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having a Section III.A.15.1 request denied, costs incurred for the duration of the period of time addressed in the Section III.A.15.1 request.

(iii) A Market Participant also may submit a filing under Section III.A.15.2(i)(a) to seek recovery of opportunity costs within the Day-Ahead Market as a result of mitigation applied to the Resource's Day-Ahead Ancillary Services Offer under Section III.A.8. To recover such opportunity costs, the Market Participant must demonstrate as part of the filing requirements of Section III.A.15.2.1(iii) and (iv) that the original, unmitigated Day-Ahead Ancillary Services Offer reflected costs anticipated by the Market Participant at the time the offer was made. The filing must be made within the time period specified for a filing to address cost recovery under Section III.A.15.2(i)(a).

III.A.15.2.1. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel, variable operating and maintenance costs, or Day-Ahead Ancillary Services close-out or input costs, or opportunity costs as described in Section III.A.15.2(iii), for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) regarding actual costs, an explanation of (a) why such actual costs exceeded the Reference Level or Day-Ahead Ancillary Services Benchmark Level costs or, (b) in the absence of mitigation, why such actual costs, as reflected in the original offer and to the extent not recovered under Section III.A.15.1, exceeded the costs as reflected in the capped offer; (iii) sufficient documentation and information supporting the basis for the original offer at the time the offer was submitted; (iv) an explanation as to why the original offer should not have been mitigated to the applicable Reference Level or Benchmark Level, or in the absence of mitigation, why the Section III.A.15.1 request should not have been denied in whole or in part; (v) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.2.2; and (vi) all requested regulatory costs in connection with the filing.

III.A.15.2.2. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the applicable Invoice, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15.2 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2.1(i), (ii), (iii), and (iv) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15.2 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.2.

III.A.15.2.3. Cost Allocation.

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

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

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

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

III.A.16.2. Standard of Review.

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

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

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

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

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

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

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

III.A.17.2.2. Quarterly Report.

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

III.A.17.2.3. Reporting on General Performance of the Capacity Market.

The performance of the Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. The Internal Market Monitor shall report on the functioning of the Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this ***Appendix A***.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

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

III.A.17.2.5. Additional Ad Hoc Reporting on Performance and Competitiveness of Markets.

In furtherance of its function under Section III.A.2 of this ***Appendix A***, including without limitation Sections III.A.2.3(e) and (k) therein, the Internal Market Monitor shall perform independent evaluations and prepare ad hoc reports on the overall competitiveness and performance of the New England Markets or particular aspects of the New England Markets, including the competitiveness and performance of a major market design change. The Internal Market Monitor shall have the sole discretion to determine when to prepare an ad hoc report and may prepare such report on its own initiative or pursuant to a request by the ISO, New England state public utility commissions or one or more Market Participants. However, the Internal Market Monitor will report on the competitiveness and performance of any new major market design change within one to three years, respectively, of the effective date of operation of the market design change, or as soon as adequate data becomes available. While the Internal Market Monitor may solicit or receive input of the External Market Monitor, Market Participants and other stakeholders, including New England state public utility commissions, the methodology and criteria used to conduct its independent analysis shall be at the sole discretion of the Internal Market Monitor. The Internal Market Monitor shall describe its methodology and criteria used in an ad hoc report of its significant findings and, if any, recommendations. The Internal Market Monitor shall file with the Commission and post to the ISO's website a final version of an ad hoc report. Thereafter, the Internal Market Monitor shall continue to report on the competitiveness and performance of any market design change that has been the subject of an ad hoc report in its quarterly or annual reports under Sections III.A.17.2.2 and III.A.17.2.4.

III.A.17.3. Periodic Reporting by the External Market Monitor.

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

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

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

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

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

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

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

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

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

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

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

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

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

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

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

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

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct, as amended from time to time and available on the ISO's website. Consistent with the ISO New England Inc. Code of Conduct, at a minimum each such monitoring unit and its employees: (a) must have no material affiliation with any Market Participant or Affiliate, (b) must have no material financial interest in any Market Participant or Affiliate with potential exceptions for mutual funds and non-directed investments, (c) must not engage in any market transactions other than the performance of their duties hereunder, (d) may not accept anything of value from a Market Participant in excess of a *de minimis* amount, and (e) must advise a supervisor in the event they seek employment with a Market Participant, and must disqualify themselves from participating in any matter that would have an effect on the financial interest of the Market Participant.

III.A.18.2. Additional Ethical Conduct Standards.

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

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

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

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of ***Appendix A***, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

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

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

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

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

- (1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);
- (2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;
- (3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;

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

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

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

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

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

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

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

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

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

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

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

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

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

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

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

III.A.21. Buyer-Side Market Power Review for the Capacity Market.

(a) Any capacity that has not been previously offered into an Annual Capacity Auction and that will be included in a Capacity Offer once it satisfies the necessary auction qualification requirements in Sections III.15.2 and III.15.3 of Market Rule 1 is subject to the provisions of this Section III.A.21. The Internal Market Monitor shall conduct a buyer-side market power review and determine a resource-specific Capacity Offer Floor Price for such capacity unless such capacity is exempted as described in this Section III.A.21. Capacity for which the Internal Market Monitor determines a Capacity Offer Floor Price pursuant to this Section III.A.21 remains subject to the provisions of this Section III.A.21 until the capacity is awarded a Capacity Supply Obligation through an Annual Capacity Auction.

(b) For the purposes of this Section III.A.21, capacity not previously offered into an Annual Capacity Auction includes the following:

(i) capacity supplied from a resource that has never been offered into an Annual Capacity Auction;

(ii) capacity supplied from a resource previously offered into an Annual Capacity Auction, where such capacity represents an increase in the resource's total capacity as compared to the highest Capacity Supply Obligation (measured in MW) awarded to the resource in a prior

Annual Capacity Auction or Forward Capacity Auction, and the increase is associated with a material change in the resource as defined in Section III.15.2.4.1(b); and

(iii) capacity supplied from a previously deactivated or retired resource, or portion thereof, that seeks to re-enter the Capacity Market pursuant to Section III.15.2.4 and that has not been offered into an Annual Capacity Auction since deactivation or retirement.

(c) For the purposes of this Section III.A.21, capacity not previously offered into an Annual Capacity Auction does not include the following:

(i) capacity supplied from an Import Capacity Resource that is (1) backed by a multi-year contract and (2) previously offered into an Annual Capacity Auction or Forward Capacity Auction while backed by that contract; or

(ii) for the purpose of the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, capacity for which a Capacity Supply Obligation had been awarded in a Forward Capacity Auction and not subsequently de-listed pursuant to a Permanent De-List Bid or a Retirement De-List Bid.

(d) A Lead Market Participant must be designated for a resource that will supply the capacity that is subject to the provisions of this Section III.A.21, notwithstanding the development or commercialization status of the resource.

III.A.21.1. Applicability of Buyer-Side Market Power Review.

Review submission requirements for capacity subject to the Internal Market Monitor's buyer-side market power review and exemptions from the Internal Market Monitor's buyer-side market power review are described in this Section III.A.21.1.

III.A.21.1.1. Capacity Not Exceeding 5 MW.

Capacity not previously offered into an Annual Capacity Auction that will be included in a Capacity Offer is not subject to the Internal Market Monitor's buyer-side market power review or a Capacity Offer Floor Price if the amount of the capacity does not exceed an Annual Qualified Capacity of 5 MW.

III.A.21.1.2. Passive Demand Response Resources.

Capacity not previously offered into an Annual Capacity Auction that will be included in a Capacity Offer and that is supplied from an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource is not subject to the Internal Market Monitor's buyer-side market power review or a Capacity Offer Floor Price.

III.A.21.1.3 Import Capacity Not Associated with Transmission Investments.

Import capacity not previously offered into an Annual Capacity Auction that will be included in a Capacity Offer is not subject to the Internal Market Monitor's buyer-side market power review or a Capacity Offer Floor Price, unless the import capacity is either:

(i) supplied from a single new External Resource, and the External Resource or import capacity supplied by the External Resource is controlled by or receiving out-of-market revenues (as defined in Section III.A.21.3(a)(ii)) from an entity or individual that (a) made or is making an investment in transmission that increases New England's import capability or (b) has a contractual arrangement with such an entity or individual, or

(ii) is controlled by or receiving out-of-market revenues (as defined in Section III.A.21.3(a)(ii)) from an Elective Transmission Upgrade Interconnection Customer as defined in Section II.47.5, Affiliate of an Elective Transmission Upgrade Interconnection Customer, or sponsor of an Elective Transmission Upgrade.

For the purposes of this Section III.A.21.1.3, the term "controlled" has the meaning set forth in Section III.A.23.4.

III.A.21.1.4. Capacity Supported by a Qualifying Load-Side Relationship Certification.

Capacity not previously offered in an Annual Capacity Auction that will be included in a Capacity Offer will not be subject to the Internal Market Monitor's buyer-side market power review or a Capacity Offer Floor Price if the Lead Market Participant for the resource supplying the capacity complies with the submission requirements described in Section III.A.21.1.5 and submits a Load-Side Relationship Certification demonstrating one of the following qualifying circumstances:

(a) the Lead Market Participant and its Affiliates or partners, if any, are not load serving entities and are neither receiving nor expecting to receive any revenues from a load serving entity, state, or political subdivision of a state that relate to the development, operation, control, or output of the resource supplying the capacity (excepting any revenues earned through an ISO-administered market); or

(b) the resource supplying the capacity is a Sponsored Policy Resource.

For the purpose of this Section III.A.21, a load serving entity is any entity that has or is the type of entity that could acquire a Capacity Load Obligation in the Capacity Market.

To demonstrate such circumstances, the Lead Market Participant must include as part of the Load-Side Relationship Certification a sworn affidavit from an officer or principal for the Lead Market Participant that includes factual detail sufficient to explain the qualifying circumstances. The Lead Market Participant must submit the Load-Side Relationship Certification to the ISO concurrent with the submission of information made pursuant to Section III.A.21.1.5. If the ISO is unable to determine from the Load-Side Relationship Certification that one of the qualifying circumstances exists, the capacity shall be subject to buyer-side market power review pursuant to Section III.A.21.2.

III.A.21.1.5. Submission of Information for Exemption or Internal Market Monitor Review.

(a) The Lead Market Participant for a resource supplying capacity not previously offered into an Annual Capacity Auction that will be included in a Capacity Offer must submit to the ISO the following, unless the capacity meets the exemption requirements of Section III.A.21.1.1, Section III.A.21.1.2, or Section III.A.21.1.3:

(i) the qualification data described and referenced in Section III.15.2.1.1(a);

(ii) the name of any Affiliates of the Lead Market Participant that are load serving entities;

(iii) for capacity supplied from a resource previously offered into an Annual Capacity Auction as described in Section III.A.21(b)(ii), information identifying any changes to the resource's design or operating characteristics and the impact of such changes on the resource's total capacity;

(iv) for capacity that satisfies either of the qualifying circumstances set forth in Section III.A.21.1.4, a Load-Side Relationship Certification as described in Section III.A.21.1.4;

(v) for capacity that does not satisfy either of the qualifying circumstances set forth in Section III.A.21.1.4, the lowest price at which the Lead Market Participant requests to offer the capacity in the Annual Capacity Auction and sufficient documentation and information for a buyer-side market power review pursuant to Section III.A.21.2. Such documentation and information must include all financial estimates, projected revenues, and cost projections for the resource supplying the capacity, including the resource's pro-forma financing support data and anticipated out-of-market revenues (as defined in Section III.A.21.3(a)(ii)). For capacity that has achieved commercial operation prior to the submission of this information, such documentation must also include all financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation.

(b) With the exception of capacity that will be offered into the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028 or the Capacity Commitment Period beginning on June 1, 2029, the Lead Market Participant may submit the information required by subsection (a) as early as the first Business Day of January of the third calendar year prior to the first Annual Capacity Auction for which the capacity may be eligible to be offered, as determined with reference to the capacity's proposed commercial operation date. For capacity that will be offered into the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028 or the Capacity Commitment Period beginning on June 1, 2029, the earliest submission date will be the first Business Day of June 2026.

(c) If not already submitted pursuant to subsection (b), the Lead Market Participant must submit the information required by subsection (a) no later than the first Business Day of June of the calendar year prior to the first Annual Capacity Auction into which the capacity will be offered pursuant to Section III.A.22.1.

(d) By the end of the fifth calendar month following the month during which the submission of information pursuant to subsection (a) was made, the ISO shall notify the Lead Market Participant of any ISO determination as to whether the capacity is exempt from buyer-side market power review pursuant to Section III.A.21.1.4 and the basis for such determination, any Capacity Offer Floor Price for the capacity, and any Internal Market Monitor determinations regarding whether a requested lowest offer price submitted pursuant to subsection (a) must be mitigated, as described in Section III.A.21.2.3. The ISO and the Internal Market Monitor shall not disclose to the Lead Market Participant any information or analysis regarding the potential impact on Capacity Clearing Prices of any offer of the capacity into the Annual Capacity Auction.

(e) A Lead Market Participant that submits a Load-Side Relationship Certification must be prepared to provide both (1) the lowest price at which the Lead Market Participant requests to offer the capacity in the Annual Capacity Auction and (2) the documentation and information described in subsection (a)(v), in the event that the ISO determines that the Load-Side Relationship Certification does not meet the requirements of Section III.A.21.1.4. If the ISO rejects a Load-Side Relationship Certification, the Lead Market Participant must promptly provide this information, and the capacity shall be subject to buyer-side market power review pursuant to Section III.A.21.2.

(f) A Lead Market Participant that submits a Load-Side Relationship Certification is under a continuing obligation through the time of the Annual Capacity Auction to withdraw the Load-Side Relationship Certification if, at any point through the time of the Annual Capacity Auction, the capacity ceases to satisfy the qualifying circumstances set forth in Section III.A.21.1.4 that provided the basis of the Load-Side Relationship Certification. If at the time of withdrawal, the Lead Market Participant submits a substitute Load-Side Relationship Certification demonstrating alternate qualifying circumstances that the ISO determines meets the requirements of Section III.A.21.1.4, then the capacity will continue to be exempt from the Internal Market Monitor's buyer-side market power review pursuant to Section III.A.21.1.4. If no substitute Load-Side Relationship Certification is submitted at the time of withdrawal and the capacity is not exempt from buyer-side market power review pursuant to Section III.A.21.1.1, Section III.A.21.1.2, or Section III.A.21.1.3, then the following shall apply:

(i) If the withdrawal occurs no later than the first Business Day of June of the calendar year prior to the Annual Capacity Auction, the Lead Market Participant must submit concurrently with the withdrawal both (1) the lowest price at which the Lead Market Participant requests to offer the capacity in the Annual Capacity Auction and (2) the documentation and information described in subsection (a)(v). The capacity shall then be subject to buyer-side market power review pursuant to Section III.A.21.2, unless a Capacity Offer Floor Price already has been calculated for the capacity subject to review. If a Capacity Offer Floor Price already has been calculated, no additional review is required.

(ii) If the withdrawal occurs later than the first Business Day of June of the calendar year prior to the Annual Capacity Auction, the capacity shall be treated as though no submission of information was made pursuant to Section III.A.21.1.5 and be assigned a Capacity Offer Floor Price as described in Section III.A.21.3(g).

(g) A Lead Market Participant that submitted a requested lowest offer price pursuant to subsection (a) is under a continuing obligation through the time of the Annual Capacity Auction to submit a Load-Side Relationship Certification if, at any point through the time of the Annual Capacity Auction, circumstances change such that either of the qualifying circumstances set forth in Section III.A.21.1.4 can be demonstrated for the capacity associated with the requested lowest offer price. If the Load-Side Relationship Certification is submitted no less than 21 days prior to the Annual Capacity Auction Offer Window and the ISO determines that the Load-Side Relationship Certification meets the requirements of Section III.A.21.1.4, then the capacity will not be subject to a Capacity Offer Floor Price, notwithstanding the results of any previously conducted buyer-side market power review.

(h) If a Lead Market Participant fails to provide a submission pursuant to subsection (a) as required pursuant to this Section III.A.21.1.5, the capacity that would be the subject of the submission will be assigned a Capacity Offer Floor Price as described in Section III.A.21.3(g).

III.A.21.2. Review for the Exercise of Buyer-Side Market Power.

The Internal Market Monitor shall review requested lowest offer prices submitted pursuant to Section III.A.21.1.5 for the potential exercise of buyer-side market power following the process described in this Section III.A.21.2 and will determine a Capacity Offer Floor Price for the capacity that is the subject of the submission.

III.A.21.2.1. Conduct Test.

The Internal Market Monitor will perform a conduct test by reviewing the information submitted pursuant to Section III. A.21.1.5 and determining a break-even price, as described in Section III.A.21.3, for the capacity subject to review. A requested lowest offer price for capacity subject to review fails the conduct test if the Internal Market Monitor determines a break-even price that exceeds the requested lowest offer price.

III.A.21.2.2. Demonstration of Lack of Incentive to Exercise Buyer-Side Market Power.

If the Lead Market Participant fails to demonstrate either of the qualifying circumstances set forth in Section III.A.21.1.4 to the ISO through a Load-Side Relationship Certification because the Lead Market Participant is or is affiliated with a load serving entity or because the Lead Market Participant receives or expects to receive revenues outside of ISO-administered markets from a load serving entity, the Lead Market Participant is entitled to submit documentation and information as part of the submission of information pursuant to Section III.A.21.1.5 to demonstrate that, notwithstanding such a relationship with a load serving entity with regard to the resource supplying the capacity subject to review, such load serving entity would be unlikely to realize a material, net financial benefit from any reduction in Annual Capacity Auction clearing prices resulting from entry of the capacity in the Annual Capacity Market. If, after consideration of such documentation and information, the Internal Market Monitor determines that a load serving entity as described in this Section III.A.21.2.2 would be unlikely to realize such a material, net financial benefit, then the Internal Market Monitor will not subject the requested lowest offer price to the mitigation described in Section III.A.21.2.3. For the avoidance of doubt, a Lead Market Participant may not utilize the provisions of this Section III.A.21.2.2 if it receives or expects to receive any revenues from a state, or from a political subdivision of a state that is not also a load serving entity, that relate to the development, operation, control, or output of the resource supplying the capacity.

As part of the documentation and information the Lead Market Participant submits pursuant to this Section III.A.21.2.2, the Lead Market Participant must include in its documentation and information a disclosure of any and all direct or indirect relationships or arrangements with a load serving entity regarding the resource supplying the capacity and any other information necessary for the Internal Market Monitor to make the determination described in this Section III.A.21.2.2.

III.A.21.2.3. Consequence of Failing the Conduct Test and Failing to Rebut Presumed Incentive.

If a requested lowest offer price for capacity subject to review fails the conduct test and the Internal Market Monitor does not determine the lack of a material, net financial benefit to a load serving entity, as described in Section III.A.21.2.2, the Internal Market Monitor-determined break-even price calculated as part of the conduct test shall be the Capacity Offer Floor Price, as described in Section III. A.21.3(d).

III.A.21.3. Capacity Offer Floor Prices.

For capacity not previously offered into an Annual Capacity Auction for which the Internal Market Monitor is required to determine a Capacity Offer Floor Price, the Internal Market Monitor shall use the methodology described in this Section III.A.21.3 to make such a determination.

(a) When determining a Capacity Offer Floor Price for any capacity not previously offered into an Annual Capacity Auction, the Internal Market Monitor shall determine a break-even price for the capacity by entering all relevant resource capital and operating costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into a capital budgeting model and calculating the break-even contribution required from the Annual Capacity Market to yield a discounted cash flow with a net present value of zero for the project.

(i) The default model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties). The model horizon shall be longer or shorter than 20 years for a resource's break-even contribution calculation, if sufficiently documented in the offer information submitted pursuant to Section III. A.21.1.5. Adjustments to the model and calculation methodology will be made for capacity supplied from certain types of Demand Capacity Resources and Distributed Energy Capacity Resources as follows:

(1) For Demand Response Assets or Distributed Energy Resources with demand reduction capability, the Internal Market Monitor will model discounted cash flows over the contract life.

(2) For Demand Response Assets or Distributed Energy Resources with demand reduction capability that are large commercial or industrial customers that use pre-existing equipment or strategies, the Internal Market Monitor will include new equipment costs and annual operating costs, such as customer incentives and sales representative commissions, as incremental costs.

(3) For Demand Response Assets or Distributed Energy Resources with demand reduction capability that are residential or small commercial customers that do not use pre-existing equipment or strategies, the Internal Market Monitor will include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs as incremental costs.

(ii) In calculating the break-even contribution for the capacity, the Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used for such calculation. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Annual Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Lead Market Participant shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(iii) For capacity supplied from a Demand Capacity Resource or Distributed Energy Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource or Distributed Energy Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response

Resource or Distributed Energy Resource Aggregation, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iv) For capacity not previously offered into an Annual Capacity Auction that has achieved commercial operation prior to the submission of information pursuant to Section III.A.21.1.5, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such capacity, the prevailing market conditions will be those that were in place at the time of the decision to construct or change the design or operating characteristics of the resource supplying the capacity.

(b) Sufficient documentation and information must be included in the submission of information pursuant to Section III.A.21.1.5 to allow the Internal Market Monitor to make the determinations described in this Section III.A.21.3. If the supporting documentation and information is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Lead Market Participant to gather further information as necessary to complete its analysis. If after consultation, the Lead Market Participant does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the capacity subject to review shall be treated as though no submission of information was made pursuant to Section III.A.21.1.5 and be assigned a Capacity Offer Floor Price as described in Section III.A.21.3(g).

(c) If the Internal Market Monitor determines that the requested offer price is equal to or greater than the Internal Market Monitor-determined break-even price, then the Capacity Offer Floor Price shall be equal to the requested offer price.

(d) If the Internal Market Monitor determines that the requested offer price is less than the Internal Market Monitor-determined break-even price and the Internal Market Monitor does not determine the lack of a material, net financial benefit to a load serving entity, as described in Section III.A.21.2.2, then the Capacity Offer Floor Price shall be equal to the Internal Market Monitor-determined break-even price.

(e) After the Seasonal Qualified Capacity Values are determined for the resource supplying the capacity subject to the Capacity Offer Floor Price, the Internal Market Monitor may recalculate the break-even price as necessary to update a Capacity Offer Floor Price such that it reflects the Seasonal Qualified

Capacity Values. During this recalculation, the Internal Market Monitor shall change only inputs and assumptions used in the initial determination of the break-even price that depend on resource capacity values. The Internal Market Monitor shall notify the Lead Market Participant of any update to the Capacity Offer Floor Price concurrently with the Seasonal Qualified Capacity Notification Deadline. The Internal Market Monitor may further update the Capacity Offer Floor Price as necessary to reflect changes in a resource's Seasonal Qualified Capacity Values that occur after the Seasonal Qualified Capacity Notification Date and shall notify the Lead Market Participant of any such further update on the same date as any notifications made by the ISO pursuant to Section III.15.2.7(d).

(f) In accordance with Section III.15.4.2.2(c), capacity having a Capacity Offer Floor Price determined pursuant to this Section III.A.21.3 that is higher than the Capacity Auction Offer Price Cap shall not be taken into account in the clearing of the Annual Capacity Auction.

(g) If a Lead Market Participant fails to provide a submission of information by the deadline set forth in Section III.A.21.1.5(c) and the capacity is not exempt from buyer-side market power review pursuant to Sections III.A.21.1.1, III.A.21.1.2, or III.A.21.1.3, the capacity will be subject to a Capacity Offer Floor Price in each Annual Capacity Auction into which the capacity is being offered that equals the Capacity Auction Offer Price Cap calculated for such Annual Capacity Auction, unless a Capacity Offer Floor Price is calculated pursuant to subsection (h)(i) of this Section III.A.21.3.

(h) Capacity for which a Capacity Offer Floor Price has been determined pursuant to this Section III.A.21.3 will remain subject to that Capacity Offer Floor Price until the capacity clears and is awarded a Capacity Supply Obligation in an Annual Capacity Auction, except as follows:

(i) If the capacity for which a Capacity Offer Floor Price has been determined does not clear the first Annual Capacity Auction into which it is offered, the Lead Market Participant may submit a request to the Internal Market Monitor to recalculate the Capacity Offer Floor Price for a subsequent Annual Capacity Auction if either (1) the cost or expected revenue assumptions for the resource have changed from those same assumptions reflected in the most recent submission of information pursuant to Section III.A.21.1.5(a) in a way that will impact the Capacity Offer Floor Price determination or (2) the Capacity Offer Floor Price had been set to the Capacity Auction Offer Price Cap. The request must be made by the submission deadline for the subsequent Annual Capacity Auction set forth in Section III.A.21.1.5(c) and must include all of the information and documentation required by

Section III.A.21.1.5(a). If the request is made on the grounds of a change in cost or expected revenue assumptions, the request must clearly and specifically identify the changed assumptions and the supporting documentation for such assumptions, and must explain how the changed assumptions will impact the Capacity Offer Floor Price calculation. The Internal Market Monitor, at its discretion, may reject a request to recalculate that does not clearly and specifically identify the changed assumptions or the supporting documentation for such assumptions, or explain the impact on the Capacity Offer Floor Price calculation.

(ii) If the capacity satisfies the requirements of Section III.A.21.1.1, then the capacity will not be subject to a Capacity Offer Floor Price, even if the Internal Market Monitor previously determined a Capacity Offer Floor Price for the capacity.

(iii) If the capacity satisfies the requirements of Section III.A.21.1.5(g), then the capacity will not be subject to a Capacity Offer Floor Price, even if the Internal Market Monitor previously determined a Capacity Offer Floor Price for the capacity.

III.A.22. Supply-Side Market Power Review for the Capacity Market

III.A.22.1. Capacity Market Offer Requirement.

(a) With the exception of resources for which the ISO has accepted a Deactivation Notification that will be in effect for the relevant Capacity Commitment Period, a resource that has previously held a Capacity Supply Obligation or has had a Capacity Offer submitted on its behalf in a prior Annual Capacity Auction is required to participate in the qualification process for the Annual Capacity Auction as described in Sections III.15.2 and III.15.3.

(b) A resource that has not previously held a Capacity Supply Obligation or has not had a Capacity Offer submitted on its behalf in a prior Annual Capacity Auction is required to participate in the qualification process for the Annual Capacity Auction as described in Sections III.15.2 and III.15.3 if the resource (1) has CNR Capability at the time of the Qualification Data Submission Deadline and (2) is in commercial operation or has a Commercial Operation Date in its interconnection agreement earlier than April 1 of the same calendar year as the Annual Capacity Auction.

(c) A Capacity Offer must be submitted to the ISO during the Annual Capacity Auction Offer Window for a resource that participates in the qualification process for the Annual Capacity Auction as described in Sections III.15.2 and III.15.3 and receives an Annual Qualified Capacity greater than 0 MW. The Capacity Offer must include a total quantity that is equal to the resource's Annual Qualified Capacity.

(d) If a Capacity Offer is not submitted to the ISO during the Annual Capacity Auction Offer Window for a resource subject to subsection (c), the ISO shall enter a Capacity Offer for the resource into the Annual Capacity Auction with the resource's Annual Qualified Capacity priced at either (i) $0.00/kW-month or (ii) for any capacity subject to a Capacity Offer Floor Price pursuant to Section III.A.21 supplied by the resource, the Capacity Offer Floor Price.

III.A.22.2. Capacity Offer Price Review for Economic Withholding.

The Internal Market Monitor shall review Proposed Capacity Offers from resources that will submit Capacity Offers in the Annual Capacity Auction as described in this Section III.A.22.2.

III.A.22.2.1. Capacity Offer Price Threshold.

For each Annual Capacity Auction, a Capacity Offer Price Threshold shall be calculated as described below in this Section III.A.22.2.1 and shall be published to the ISO's website no later than one month before the Capacity Offer Review Submission Deadline. This publication shall include the preliminary value calculated pursuant to subsection (a) below, whether the preliminary value was constrained by either of the limitations described in subsection (b) below, the margin value as calculated pursuant to subsection (c) below, and the final value as calculated pursuant to subsection (d) below.

(a) Subject to the limitations described in subsection (b) and to subsection (e) below, a preliminary value of the Capacity Offer Price Threshold shall be calculated as the average of: (i) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone from the immediately preceding Annual Capacity Auction (provided, however, that if there is a second run of the primary auction-clearing process pursuant to Section III.15.4.2.4, the resulting Rest-of-Pool Capacity Zone clearing price from that run shall be used instead); and (ii) the price at which the total amount of capacity clearing in the immediately preceding Annual Capacity Auction intersects the System-Wide Capacity Demand Curve for the upcoming Annual Capacity Auction that is filed with the

Commission pursuant to Section III.12.3(a) in advance of the upcoming Annual Capacity Auction.

(b) The preliminary value of the Capacity Offer Price Threshold shall not be higher than 75 percent of the Net CONE value for the upcoming Annual Capacity Auction. The preliminary value of the Capacity Offer Price Threshold shall not be lower than 75 percent of the clearing price applicable pursuant to (a)(i) of this Section III.A.22.2.1, except as needed to ensure that it is not higher than 75 percent of the Net CONE value for the upcoming Annual Capacity Auction.

(c) A margin value shall be calculated using the following formula:

$$Margin = \$1/kW\text{-}month \times \left[\frac{(0.75 \times Net\ CONE_{upcoming\ ACA}) - COPT_{preliminary}}{(0.75 \times Net\ CONE_{upcoming\ ACA})}\right]$$

(d) The final value of the Capacity Offer Price Threshold for the upcoming Annual Capacity Auction shall be equal to the preliminary value of the Capacity Offer Price Threshold calculated pursuant to Sections III.A.22.2.1(a) and III.A.22.2.1(b) plus the margin value calculated pursuant to Section III.A.22.2.1(c).

(e) For the purpose of determining a preliminary value of the Capacity Offer Price Threshold for the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, the “immediately preceding Annual Capacity Auction” shall mean the Forward Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2027.

III.A.22.2.2. Applicability of Capacity Offer Price Review.

(a) Except with regard to capacity subject to a Capacity Offer Floor Price pursuant to Section III.A.21 and Capacity Offers that will meet the requirements set forth in subsection (d) below, a Lead Market Participant that seeks to submit a Capacity Offer that specifies prices above the Capacity Offer Price Threshold for the Annual Capacity Auction must submit a Proposed Capacity Offer to the Internal Market Monitor for review pursuant to Section III.A.22.2.3 and must include the additional documentation described in that section. With the submission of a Proposed Capacity Offer, the Lead Market Participant must notify the ISO if the resource for which the Proposed Capacity Offer is submitted will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests) if it is not awarded a Capacity Supply Obligation for the Capacity Commitment Period.

(b) The Proposed Capacity Offer and all documentation required for the Internal Market Monitor's review must be submitted no later than the Capacity Offer Review Submission Deadline established for the Annual Capacity Auction. If a Lead Market Participant does not submit a Proposed Capacity Offer and the required supporting documentation to the Internal Market Monitor by the Capacity Offer Review Submission Deadline, the Capacity Offer submitted for the resource during the Annual Capacity Auction Offer Window must not specify any prices above the Capacity Offer Price Threshold.

(c) A price in a Capacity Offer specified for capacity subject to a Capacity Offer Floor Price pursuant to Section III.A.21 is not subject to the Internal Market Monitor's review pursuant to Section III.A.22.2.3, but the specified price may only be greater than the Capacity Offer Floor Price if the price is below the Capacity Offer Price Threshold. If the Capacity Offer Floor Price is at or above the Capacity Offer Price Threshold, the specified price must equal the Capacity Offer Floor Price.

(d) Notwithstanding subsection (a) above, a Lead Market Participant that seeks to submit a Capacity Offer that specifies a price above the Capacity Offer Price Threshold for the Annual Capacity Auction is not required to submit a Proposed Capacity Offer if (i) the Capacity Offer will not contain more than one price-quantity pair that has a specified price above the Capacity Offer Price Threshold and (ii) the difference between the MW quantity of such price-quantity pair and the MW quantity of the price-quantity pair that specifies the next lowest price is equal to or less than the ambient air condition MW verified through the process set forth in Section III.15.2.1.5. For the purposes of Sections III.15.4.1, any Capacity Offer that qualifies for this exemption from the Proposed Capacity Offer submission requirement shall be deemed to have met the requirements set forth in (i) through (iii) of Section III.15.4.1(e) and to have been determined an Allowable Capacity Offer Price of $0.01/kW-month greater than the Capacity Auction Offer Price Cap for the price-quantity pair. Such price-quantity pair will not be subject to the mitigation set forth in Sections III.A.22.2.4(c) and (d). Nothing in this subsection (d), however, shall limit or prevent the Internal Market Monitor from reviewing any ambient air condition adjustment or any Capacity Offer that qualifies for the exemption set forth in this subsection (d) for the potential exercise of market power, or to request additional information from the Lead Market Participant submitting the Capacity Offer to enable the Internal Market Monitor to make such a determination and take any appropriate steps.

III.A.22.2.3. Review of Capacity Offer Prices Exceeding Threshold.

(a) The Internal Market Monitor shall review each Proposed Capacity Offer with a price above the Capacity Offer Price Threshold to determine whether the offer is consistent with the following: (1) the resource's net going forward costs; (2) reasonable expectations about the resource's Capacity Performance Payments; (3) reasonable risk premium assumptions; and (4) the resource's reasonable opportunity costs, all as determined pursuant to this Section III.A.22.2.3. Sufficient documentation and information about each offer component must be included in the Section III.A.22.2.2(a) submittal to allow the Internal Market Monitor to make the requisite determinations about each cost component. The Section III.A.22.2.2(a) submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of its content, including reported costs, the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a resource with a Capacity Supply Obligation, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments, cash flows, opportunity costs, and risk premiums, and shall be subject to audit upon request by the ISO. The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the other existing or potential new resources controlled by the Lead Market Participant) at any time to address any questions or concerns regarding the data submitted, as appropriate. In determining the consistency of Proposed Capacity Offer prices with the foregoing cost components, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio. In its review of the Proposed Capacity Offer, the Internal Market Monitor shall treat ambient air condition MW verified through the process set forth in Section III.15.2.1.5, if any, as physically unavailable and make its determinations pursuant to this Section III.A.22.2.3 accordingly.

(b) The Internal Market Monitor shall review each Proposed Capacity Offer and, after due consideration and consultation with the Lead Market Participant, as appropriate, shall develop Cost-Based Reference Prices for comparison with the prices specified in the Proposed Capacity Offer that are above the Capacity Offer Price Threshold. The Internal Market Monitor shall calculate the Cost-Based Reference Prices in a manner that is consistent with the sum of the resource's net going forward costs plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable risk premium assumptions plus reasonable opportunity costs. The Internal Market Monitor's comparison of the Cost-Based Reference Prices to the prices specified in the Proposed Capacity Offer will result in Allowable Capacity Offer Prices as follows:

(i) For each price-quantity pair in the Proposed Capacity Offer that specifies a price above the Capacity Offer Price Threshold, the Internal Market Monitor shall calculate a Cost-Based Reference Price for the MW quantity specified in the price-quantity pair.

(ii) If the price specified in the price-quantity pair of the Proposed Capacity Offer is equal to or less than 110 percent of the Cost-Based Reference Price for such price-quantity pair, then the Allowable Capacity Offer Price for the price-quantity pair shall be equal to the price specified for the price-quantity pair. If the price specified for the price-quantity pair is more than 110 percent of the Cost-Based Reference Price, then the Allowable Capacity Offer Price for the price quantity pair shall be equal to the Cost-Based Reference Price.

(iii) If replacement of the prices specified for price-quantity pairs in the Proposed Capacity Offer with the Allowable Capacity Offer Prices determined pursuant to (i) and (ii) would result in a Capacity Offer that does not comply with the requirements of Section III.15.4.1(d), the Internal Market Monitor, after consultation with the Lead Market Participant, may adjust the Allowable Capacity Offer Price for any price-quantity pair as necessary to ensure that the Proposed Capacity Offer, if submitted pursuant to Section III.15.4.1 and mitigated pursuant to Section III.A.22.2.4(c), would comply with the requirements of Section III.15.4.1(d).

(c) If the Internal Market Monitor establishes an Allowable Capacity Offer Price for a price-quantity pair that does not equal the price specified by the Lead Market Participant for the price-quantity pair in the Proposed Capacity Offer, an explanation of the Allowable Capacity Offer Price based on the Internal Market Monitor review shall be provided to the Lead Market Participant at the time the Internal Market Monitor notifies the Lead Market Participant of the results of the Internal Market Monitor's Proposed Capacity Offer price review. Such explanation shall explain the Internal Market Monitor's determinations with respect to the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor.

III.A.22.2.3.1. Net Going Forward Costs.

The Lead Market Participant for a resource that submits a Proposed Capacity Offer with a price above the Capacity Offer Review Threshold shall report expected net going forward costs for the applicable Capacity Commitment Period in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. A Proposed Capacity Offer price shall be evaluated for consistency with the capacity's net going forward costs based on a review of the data submitted in the following formula:

$$\textit{Net Going Forward Costs} = \frac{(GFC - IMR)}{(CQ_{Summer,}\ kW) \times (12\ months)}$$

Where:

GFC = annual going forward costs, in dollars. These are the expected costs and capital expenditures that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a resource with a Capacity Supply Obligation during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Proposed Capacity Offer that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period if it is not awarded a Capacity Supply Obligation for the Capacity Commitment Period. Expenses, including financial obligations, incurred prior to the capacity auction that cannot be recovered, reimbursed, compensated, waived, or cancelled should the resource not be awarded a Capacity Supply Obligation are considered unavoidable and shall not be included. The expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area may be included for Import Capacity Resources.

$CQ_{Summer}kW$ = capacity, in kilowatts, for which the price specified in the Proposed Capacity Offer is above the Capacity Offer Price Threshold. In no case shall this value exceed the resource's summer Qualified Capacity.

IMR = expected annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Proposed Capacity Offer that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be calculated by subtracting all submitted cost data representing the cumulative expected cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the resource's total ISO market revenues. In the case of a resource that has indicated that the resource will be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00.

III.A.22.2.3.2. Expected Capacity Performance Payments.

The Lead Market Participant for a resource that submits a Proposed Capacity Offer with a price above the Capacity Offer Review Threshold shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.A.22.2.3.3. Risk Premium.

The Lead Market Participant for a resource that submits a Proposed Capacity Offer with a price above the Capacity Offer Review Threshold shall also provide documentation separately detailing any risk premium included in the price. This documentation must address all components of physical and financial risk reflected in the price, including, for example, catastrophic events, a higher-than-expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs described in Section III.A.22.2.3.1 may be included in this risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the Annual Capacity Market is consistent with the participant's corporate risk management practices.

III.A.22.2.3.4. Opportunity Costs.

To the extent that a Capacity Resource submitting a Proposed Capacity Offer with a price above the Capacity Offer Review Threshold has additional opportunity costs that are not reflected in the net going forward costs, net present value of expected cash flows, expected Capacity Performance Payments, discount rate, or risk premium components of the price, the Lead Market Participant must include in the submission to the Internal Market Monitor evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.15.3.6, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.A.22.2.3.5. Review as Applied to Stations having Common Costs.

Where a resource at a Station having Common Costs elects to submit a Proposed Capacity Offer with a price above the Capacity Offer Review Threshold, the provisions of this Section III.A.22.2.3.5 shall apply.

(a) **Submission of Cost Data.** In addition to the information required elsewhere in this Section III.A.22.2.3, a Proposed Capacity Offer submitted by a resource that is associated with a Station having Common Costs must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

(b) **Internal Market Monitor Review of Stations having Common Costs.** The Internal Market Monitor will review each price specified in the Proposed Capacity Offer that is above the Capacity Offer Price Threshold from a resource that is associated with a Station having Common Costs pursuant to the following methodology:

(i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.

(ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the asset offer order.

(iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive failure to clear the Annual Capacity Auction by each individual asset in asset offer order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of Capacity Offer price-quantity pairs as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The Capacity Offer price-quantity pairs of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable price-quantity pair for use in the Annual Capacity Auction.

The Internal Market Monitor will compare a Capacity Offer price developed using the adjusted composite costs to the price specified in the Proposed Capacity Offer submitted by the resource that is associated with a Station having Common Costs and determine an Allowable Capacity Offer Price as described in Section III.A.22.2.3(b).

III.A.22.2.3.6. Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall use the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent, when relevant to its review pursuant to this Section III.A.22.2.3.

Age of Existing Resource (years)	**Remaining Life (years)**	**Annual Rate of Capital Cost Recovery**
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, along with its documentation submitted pursuant to Section III.A.22.2.2(b). The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource's annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{Cost\ Of\ Capital}{(1-(1+CostOfCapital)^{-RemainingLife})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the resource, based on the age of the resource, as indicated in the table above.

III.A.22.2.4 Results of Capacity Offer Price Review.

(a) Concurrent with the Seasonal Qualified Capacity Notification Date for the Annual Capacity Auction, the ISO shall notify the Lead Market Participant that submitted a Proposed Capacity Offer concerning the result of the Internal Market Monitor's Proposed Capacity Offer price review conducted pursuant to Section III.A.22.2.3 and include the information described in Section III.A.22.2.3(c).

(b) After the notification described in subsection (a), the Internal Market Monitor may redetermine any Allowable Capacity Offer Price, as necessary, to reflect changes in a resource's Seasonal Qualified Capacity Values that occur after the Seasonal Qualified Capacity Notification Date or to correct any errors in the initial determination of the Allowable Capacity Offer Price. The Internal Market Monitor shall notify the Lead Market Participant of any such redetermination on the same date as any notifications made by the ISO pursuant to Section III.15.2.7(d).

(c) For resources for which an Allowable Capacity Offer Price was established pursuant to Section III.A.22.2.3, the ISO shall replace a price specified in a price-quantity pair of the resource's Capacity Offer in the Annual Capacity Auction with a price as set forth in subsection (d), under the following circumstances:

(i) the resource is associated with a pivotal supplier, as determined pursuant to the pivotal supplier test set forth in Section III.A.23; and

(ii) the price specified in the price-quantity pair exceeds the greater of the Allowable Capacity Offer Price established for such price-quantity pair and the Capacity Offer Price Threshold determined pursuant to Section III.A.22.2.1.

(d) For the purposes of subsection (c), the ISO shall replace a price specified in a price-quantity pair of the Capacity Offer with the greater of (i) the Allowable Capacity Offer Price established for the price-quantity pair and (ii) the Capacity Offer Price Threshold.

III.A.22.3. Request for Additional Capacity Cost Recovery.

If as a result of mitigation applied to a Capacity Offer pursuant to Section III.A.22.2.4(c) a Lead Market Participant believes that it will not recover the costs to its Capacity Resource of meeting the Capacity Supply Obligation for the Capacity Commitment Period, as reflected in the Capacity Offer submitted for the resource, the Lead Market Participant may submit a filing to the Commission pursuant to Section 205 of the Federal Power Act in accordance with this Section III.A.22.3.

III.A.22.3.1. Threshold Conditions for Filing a Request.

To be eligible to make a Section 205 filing pursuant to this Section III.A.22.3, the following threshold conditions must have been met:

(a) the Capacity Offer submitted by the Lead Market Participant for the Capacity Resource in the Annual Capacity Auction must have at least one price-quantity pair that was submitted as part of a Proposed Capacity Offer and for which the Internal Market Monitor determined an Allowable Capacity Offer Price pursuant to Section III.A.22.2.3;

(b) the price specified in such price-quantity pair must have been replaced pursuant to Section III.A.22.2.4(c) prior to entry of the Capacity Offer into the Annual Capacity Auction; and

(c) some portion of the MW quantity specified in such price-quantity pair that is also included in the Capacity Offer's Above-Threshold Offer Segment must have been awarded a Capacity Supply Obligation in the Annual Capacity Auction.

III.A.22.3.2. Relief Available Through Filing.

(a) The Section 205 filing may request the following relief from the Commission:

(i) additional costs associated with the Capacity Supply Obligation awarded to the Capacity Resource in the Annual Capacity Auction, to be paid on a kW-month basis, at a price that is measured as the positive difference between (1) the lowest price specified in the Capacity Offer for the amount of MW of the Capacity Supply Obligation for which the Lead Market Participant seeks additional cost recovery and (2) the Capacity Clearing Price applicable to the Capacity Supply Obligation; and

(ii) regulatory costs associated with the filing.

(b) A Lead Market Participant may not request a cost recovery rate that exceeds a rate calculated in accordance with subsection (a)(i). Notwithstanding subsection (a)(i), the Commission is not required to use a price specified in the Capacity Offer for the determination of a cost recovery rate if the Capacity Resource's costs of meeting its Capacity Supply Obligation are, on a kW-month basis, lower than such price.

III.A.22.3.3. Timing of Filing.

A Section 205 filing made pursuant to this Section III.A.22.3 must be made within sixty days after the ISO publicly publishes the results of the Annual Capacity Auction in accordance with Section III.15.4.3.

III.A.22.3.4. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include the following:

(a) the Proposed Capacity Offer, all documentation and information submitted to the Internal Market Monitor pursuant to Section III.A.22.2, and any additional documentation and information relevant to the Proposed Capacity Offer that was submitted to the Internal Market Monitor during any consultation with the Internal Market Monitor before, during, or after the formal review process described in Sections III.A.22.2 and III.A.22.3;

(b) the Internal Market Monitor's notification pursuant to Section III.A.22.2.4(a) and any explanation provided as part of that notification pursuant to Section III.A.22.2.3(c);

(c) all price-quantity pairs and other parameters in the Capacity Offer submitted to the ISO for entry into the Annual Capacity Auction;

(d) identification of the price-quantity pairs contained in the Capacity Offer that the Lead Market Participant claims have been improperly mitigated pursuant to Section III.A.22.2.4(c);

(e) identification of the amount of MW of the Capacity Supply Obligation for which the Lead Market Participant seeks additional cost recovery;

(f) an explanation as to the alleged error committed by the Internal Market Monitor in determining the Cost-Based Reference Price for the MW amount identified pursuant to subsection (e);

(g) the Internal Market Monitor's written response to the request for relief, provided pursuant to Section III.A.22.3.5; and

(h) all requested regulatory costs in connection with the filing.

III.A.22.3.5. Review by Internal Market Monitor Prior to Filing.

Within twenty days after the ISO publicly publishes the results of the Annual Capacity Auction, a Lead Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.22.3 shall submit to the Internal Market Monitor a complete, advance copy of the filing with all of the material described in Section III.A.22.3.4, with the exception of the material described in Section III.A.22.3.4(g). Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the request for additional cost recovery. The Lead Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing, as described in Section III.A.22.3.4(g).

III.A.22.3.6. Payments and Charges Related to the Additional Cost Recovery.

(a) In the event that the Commission accepts a filing for cost recovery under this section, the ISO shall adjust the Capacity Resource's monthly capacity payment calculated pursuant to Section III.15.8.1.1(a) to reflect the additional cost recovery rate for the portion of the Capacity Resource's Capacity Supply Obligation to which additional cost recovery applies. With respect to monthly capacity payments made prior to implementation of a Commission-accepted additional cost recovery rate, the ISO shall issue a single lump sum payment reflecting the additional cost recovery rate.

(b) The ISO shall allocate costs associated with payments made pursuant to subsection (a) in accordance with the cost allocation provisions in Section III.15.8.5.1 that apply to Annual Capacity Auction costs. Charges for the lump sum payment made pursuant to subsection (a) shall be determined in a way that is consistent with a Market Participant's Capacity Load Obligation during each Obligation Month covered by the lump sum payment.

(c) With respect to any regulatory costs accepted by the Commission, the ISO shall apportion the sum total of such regulatory costs equally among the twelve months of the Capacity Commitment Period. Each monthly amount shall be added to the Capacity Resource's monthly capacity payment, and any monthly amounts applicable to monthly capacity payments made prior to implementation of a Commission-accepted additional cost recovery rate shall be added to the lump sum payment set forth in subsection (a). The ISO shall allocate costs associated with payments of such regulatory costs consistent with the allocation methodology set forth in subsection (b).

III.A.23. Pivotal Supplier Test for the Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to conducting the Annual Capacity Auction at the system level and for each import-constrained Capacity Zone. For the purpose of performing the pivotal supplier test as described in this Section III.A.23.1, the Capacity Resources that will be included in the calculations described herein are the Capacity Resources that will be entered into the Annual Capacity Auction for which the test is being performed.

A Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's Annual Qualified Capacity, the ability to meet the relevant requirement is less than the requirement.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

III.A.23.1.1. System-Level Requirement.

At the system level, the ability to meet the relevant requirement is the sum of the following:

(a) The total Annual Qualified Capacity from all Generating Capacity Resources and Demand Capacity Resources in the Rest-of-Pool Capacity Zone;

(b) For each modeled import-constrained Capacity Zone, the greater of:

(1) the total Annual Qualified Capacity from all Generating Capacity Resources and Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of Annual Qualified Capacity from Import Capacity Resources over the interface, and;

(2) the Local Sourcing Requirement of the import-constrained Capacity Zone;

(c) For each modeled nested export-constrained Capacity Zone, the lesser of:

(1) the total Annual Qualified Capacity from all Generating Capacity Resources and Demand Capacity Resources within the nested export-constrained Capacity Zone plus, for each external interface connected to the nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of Annual Qualified Capacity from Import Capacity Resources over the interface, and;

(2) the Maximum Capacity Limit of the nested export-constrained Capacity Zone;

(d) For each modeled export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, the lesser of:

(1) the total Annual Qualified Capacity from all Generating Capacity Resources and Demand Capacity Resources within the export-constrained Capacity Zone, excluding the total Annual Qualified Capacity from Generating Capacity Resources and Demand Capacity Resources within a nested export-constrained Capacity Zone, plus, for each external interface connected to the export-constrained Capacity Zone that is not included in any nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of Annual Qualified Capacity from Import Capacity Resources over the interface, excluding the contribution from any nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;

(2) the Maximum Capacity Limit of the export-constrained Capacity Zone minus the contribution from any associated nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c);

(e) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of:

(1) the capacity transfer limit of the interface (net of tie benefits), and;

(2) the total amount of Annual Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.1.2. Import-Constrained Capacity Zone Requirement.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

(a) The total Annual Qualified Capacity from all Generating Capacity Resources and Demand Capacity Resources located within the import-constrained Capacity Zone; and

(b) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of Annual Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

Annual Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

(a) If the removal of a supplier's Annual Qualified Capacity in an export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1.1(c) or Section III.A.23.1.1(d) for that export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.

(b) If the removal of a supplier's Annual Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1.1(e) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(c) If the removal of a supplier's Annual Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1.2 for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(d) If a supplier whose only Annual Qualified Capacity is a single capacity resource with a Capacity Offer that (i) is not subject to rationing, and (ii) contains only one price-quantity pair for the entire Annual Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers that are determined to be pivotal and subject to the mitigation described in Section III.A.22.2.4(c) as soon as practicable after the close of the Annual Capacity Auction Offer Window and before the Annual Capacity Auction results are determined.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the Annual Qualified Capacity of a supplier includes the capacity of Generating Capacity Resources, Demand Capacity Resources, and Import Capacity Resources that is controlled by the supplier or its Affiliates.

For purposes of determining the Annual Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Deactivation Notification Package Submission and Review.

III.A.24.1. Deactivation Notifications Requiring Workbook Submission and Review.

A Lead Market Participant seeking to permanently remove all or part of a resource from the Annual Capacity Market or from all New England Markets must follow the Deactivation Notification process pursuant to Section II.52, including the timely and complete submission of a Deactivation Notification Package. For each Deactivation Notification representing the deactivation of greater than 20 MW, the Deactivation Notification Package shall include the cost workbooks and supporting materials described in Section III.A.24.2 for review by the Internal Market Monitor. If more than one Deactivation Notification is submitted by a single Lead Market Participant or its Affiliates (as used in Section III.A.24.6) and the sum of all such Deactivation Notifications in aggregate is greater than 20 MW, then the Lead Market

Participant must timely submit each such Deactivation Notification Package, including the cost workbooks and supporting materials described in Section III.A.24.2, as if each deactivation were greater than 20 MW. The Internal Market Monitor has no obligation to review a Deactivation Notification Package if the Deactivation Notification provides notice of either: (a) deactivation of the only resource controlled by a Lead Market Participant or its Affiliates participating in the Annual Capacity Market; or (b) deactivation of all resources controlled by a Lead Market Participant or its Affiliates participating in the Annual Capacity Market, where the term "control" has the meaning set forth in Section III.A.24.6.

Resources requiring review under Section III.A.24.1 that deactivate without submitting the complete information required by Section III.A.24.2 by the Deactivation Notification Deadline set forth in Section II.52.1 may be subject to referral to the Commission's Office of Enforcement in accordance with Section III.A.19 if the Internal Market Monitor has reason to believe a Market Violation has occurred. In instances where a resource deactivates without submitting the complete information required by Section III.A.24.2, the Internal Market Monitor will determine the Proxy Capacity Offer of the resource pursuant to Section III.A.24.7 and include the Proxy Capacity Offer in the deactivation determinations filing pursuant to Section III.A.24.9.

III.A.24.2. Submission of Cost Workbooks and Supporting Materials.

Lead Market Participants submitting a Deactivation Notification Package subject to review under Section III.A.24.1 shall submit completed cost workbooks based on the latest Deactivation Notification cost workbooks posted to the ISO's website. The submitted cost workbooks shall include or be accompanied by sufficient documentation and information about each cost workbook component to allow the Internal Market Monitor to make the requisite determinations regarding their validity and the economic viability of the deactivating resource. Lead Market Participants submitting a Deactivation Notification Package shall include in their submission identifying information relating to all Annual Qualified Capacity that the Lead Market Participant and its Affiliates control (as that term is defined in Section III.A.24.6) including all capacity the control of which it has contracted to a third party.

Lead Market Participants may elect to submit the relevant cost workbooks and supporting materials for a completeness determination by the Internal Market Monitor no earlier than 90 days, but no later than 30 days, before the Deactivation Notification Deadline. No later than ten business days before the Deactivation Notification Deadline, the Internal Market Monitor shall notify those Lead Market Participants submitting materials for a completeness determination that either: (a) the submission has been determined to be complete; or (b) the submission has been determined to be incomplete, and identifying any aspects of the workbook or supporting materials that are deemed incomplete. Submission of a cost workbook and supporting materials for a completeness determination is optional and does not eliminate the requirement to submit a Deactivation Notification and Deactivation Notification Package on or immediately before the Deactivation Notification Deadline.

III.A.24.3. Internal Market Monitor Review of Deactivation Notification Package.

The Internal Market Monitor shall review all Deactivation Notification Packages requiring review pursuant to Section III.A.24.1 that the Internal Market Monitor determines contain a complete submission of cost workbooks and supporting material submitted on or before the Deactivation Notification Deadline for the relevant Capacity Commitment Period. The Internal Market Monitor is under no obligation to review Deactivation Notifications that it deems to be incomplete at the time of the Deactivation Notification Deadline due to incomplete cost workbooks and supporting materials.

The Internal Market Monitor shall review each timely-submitted and complete Deactivation Notification Package requiring review pursuant to Section III.A.24.1 to determine whether the economic basis for the deactivation is consistent with: (1) the net present value of the resource's expected cash flows (as determined pursuant to Section III.A.24.4.1); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.A.24.4.2); and (3) the resource's reasonable opportunity costs (as determined pursuant to Section III.A.24.4.3). The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the submission is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, and reasonable opportunity costs. In making this determination, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the other existing or potential new resources controlled by the Lead Market Participant) after the Deactivation Notification Deadline for resources requiring review under Section III.A.24 to address any questions or concerns regarding the data submitted, as appropriate.

III.A.24.4. Net Present Value of Expected Cash Flows.

For those Capacity Resources subject to Internal Market Monitor review pursuant to Section III.A.24.1, the net present value of a Capacity Resource's expected cash flows shall be determined as described in this Section III.A.24.4.

III.A.24.4.1. Net Present Value of Expected Cash Flows Formula.

The Lead Market Participant for a Capacity Resource that submits a Deactivation Notification that is to be reviewed by the Internal Market Monitor shall report all expected costs, revenues, prices, discount rates and capital expenditures in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. The Internal Market Monitor will review the Lead Market Participant's submitted data to ensure that it is consistent with overall market conditions and reflects expected values. The Internal Market Monitor will adjust any data that are inconsistent with overall market conditions or do not reflect expected values. The Internal Market Monitor shall enter all relevant expected costs, revenues, prices, discount rates and capital expenditures into a capital budgeting model and shall determine the net present value of the Capacity Resource's expected cash flows as follows:

The net present value of the Capacity Resource's expected cash flows is equal to (i) the net present value of the Capacity Resource's net annual expected cash flows over the resource's remaining economic life (as determined below) plus the net present value of the resource's expected terminal value, using the resource's discount rate, divided by (ii) the product of the resource's Qualified Capacity (in kilowatts) and 12 months.

The Capacity Resource's net annual expected cash flow for the first Capacity Commitment Period of the resource's remaining economic life (i.e., the Capacity Commitment Period associated with the Deactivation Notification) is the resource's expected annual net operating profit, including expected capacity revenues, less its expected capital expenditures in the Capacity Commitment Period.

The Capacity Resource's net annual expected cash flow for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life is the resource's expected annual net operating profit less its expected capital expenditures in the Capacity Commitment Period.

Where:

Expected net operating profit, in dollars, is the Lead Market Participant's expected annual profit that might otherwise be avoided or not accrued if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period. Expected labor, maintenance, taxes, insurance, administrative and other normal expenses that can be avoided or not incurred if the resource is deactivated may be included. Service of debt is not an avoidable cost and may not be included.

Expected capacity revenues, in dollars, are the forecasted annual expected capacity revenues based on the Lead Market Participant's forecasted expected capacity prices for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life. The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the forecasted expected capacity prices. The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions about expected resource additions, resource deactivations, estimated Installed Capacity Requirements, estimated Local Sourcing Requirements, expected market conditions, and any other assumptions used to develop the forecasted expected capacity prices in each Capacity Commitment Period.

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the forecasted expected capacity prices, the Internal Market Monitor will replace the Lead Market Participant's forecasted expected capacity prices with the Internal Market Monitor's estimate thereof in each of the subsequent Capacity Commitment Periods of the resource's remaining economic life.

Expected capital expenditures, in dollars, are the Lead Market Participant's expected capital investments that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Periods.

Expected terminal value, in dollars, for resources with five years or less of remaining economic life, is the Lead Market Participant's expected revenue less expected costs associated with deactivating the resource. For resources with more than five years of remaining economic life, the expected terminal value in the fifth year of the evaluation period is the Lead Market Participant's expected revenue less expected costs associated with deactivating the resource at the end of the resource's economic life plus the net present value of the Capacity Resource's net annual expected cash flows from the sixth year of the evaluation period through the end of the resource's remaining economic life, using the resource's discount rate.

Discount rate is a value reflecting the Lead Market Participant's weighted average cost of capital for the Capacity Resource adjusted to reflect the risk to cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.A.24.4.

The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the weighted average cost of capital for the Capacity Resource adjusted for risk. The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions associated with the cost of capital, risks and any other assumptions used to develop the weighted average cost of capital for the Capacity Resource adjusted for risk. If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the weighted average cost of capital for the Capacity Resource adjusted for risk, the Lead Market Participant has included risks not associated with cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.A.24.4 or the Lead Market Participant has submitted costs, revenues, capital expenditures or prices that are not reflective of expected values, the Internal Market Monitor will replace the Lead Market Participant's discount rate with a value determined by the Internal Market Monitor.

The Internal Market Monitor shall calculate the Capacity Resource's remaining economic life, using evaluation periods ranging from one to five years with year one being the Capacity Commitment Period associated with the Deactivation Notification. For each evaluation period, the Internal Market Monitor will calculate the net present value of (a) the annual expected net operating profit minus annual expected capital expenditures assuming the Capacity Clearing Price for the first year is equal to the Internal Market Monitor's estimate of the Capacity Auction Offer Price Cap and (b) the expected terminal value of the resource at the end of the given evaluation period. The economic life is the evaluation period in which a resource's net present value is maximized.

III.A.24.4.2. Expected Capacity Performance Payments.

The Lead Market Participant for a Capacity Resource that submits a Deactivation Notification that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.A.24.4.3. Opportunity Costs.

To the extent that a Capacity Resource submitting Deactivation Notification has additional opportunity costs that are not reflected in the net going forward costs, net present value of expected cash flows, expected Capacity Performance Payments, discount rate, or risk premium components of the bid, the Lead Market Participant must include evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.15.3.6, capital projects required to operate the plant as a capacity resource or for other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.A.24.4.4. Stations Having Common Costs.

Deactivation Notifications submitted by a Generating Capacity Resource that is associated with a Station having Common Costs and seeking to deactivate must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs. The Internal Market Monitor will review each Deactivation Notification from a Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

(i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.

(ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred deactivation order.

(iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive deactivation of each individual asset in preferred deactivation order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically nonincreasing set of prices as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The price of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable bid for use in the Capacity Auction.

The Internal Market Monitor will compare a price developed using the adjusted composite costs to the Deactivation Notification submitted by the Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted price is greater than the price developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will establish an Internal Market Monitor-calculated price as described in Section III.A.24.5 and, if the resource is determined to be deactivating to the benefit of a portfolio pursuant to III.A.24.6, the Internal Market Monitor shall use the Internal Market Monitor calculated price as the Proxy Capacity Offer Price pursuant to III.A.24.7.

III.A.24.5. Conduct Test.

The Internal Market Monitor shall review those Deactivation Notifications submitted pursuant to Section III.A.24.1 to determine whether the economic basis for a Deactivation Notification and associated cost workbooks are consistent with the reasonable net present value of the resource's expected cash flows, reasonable expectations about the resource's Capacity Performance Payments, and the resource's reasonable opportunity costs. After due consideration and consultation with the Lead Market Participant, as appropriate, the Internal Market Monitor shall develop a first-year break-even price based on the cost workbooks and supporting materials submitted by the Lead Market Participant. The Internal Market Monitor shall also calculate a first-year break-even price based on the Internal Market Monitor's reasonable expectations regarding net present value of the resource's expected cash flows, the resource's Capacity Performance Payments, and the resource's opportunity costs. If the first-year expected Capacity Clearing Price submitted by the Lead Market Participant is more than 10% greater than the first-year break-even price calculated based on the Internal Market Monitor's reasonable expectations regarding the net present value of the resource's expected cash flows, the resource's Capacity Performance Payments, and the resource's opportunity costs, then that resource fails the conduct test. For those resources failing the conduct test, the Internal Market Monitor shall perform a further review of the Lead Market Participant's portfolio pursuant to III.A.24.6. Resources that do not fail the conduct test shall deactivate consistent with the terms of their Deactivation Notification unless delaying deactivation pursuant to Section II.53.

III.A.24.6. Portfolio Benefit Test.

The portfolio benefit test is performed for each Lead Market Participant submitting a Deactivation Notification subject to Internal Market Monitor review that has failed the conduct test set forth in Section III.A.24.5. The test will be performed as follows:

If

i. The annual capacity revenue from the Lead Market Participant's total Annual Qualified Capacity, not including the Annual Qualified Capacity associated with the Deactivation Notification, is greater than

ii. the annual capacity revenue from the Lead Market Participant's total Annual Qualified Capacity, including the Annual Qualified Capacity associated with the Deactivation Notifications for resources controlled by the Lead Market Participant that failed the conduct test as calculated pursuant to subsection v. below, then

iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the portfolio benefit test.

Where,

iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total Annual Qualified Capacity not including the Annual Qualified Capacity associated with the Deactivation Notification is calculated as the product of (a) the Lead Market Participant's total Annual Qualified Capacity not including the Annual Qualified Capacity associated with the Deactivation Notification that is the subject of the review and (b) the Internal Market Monitor-simulated Capacity Clearing Price not including the Annual Qualified Capacity associated with the Deactivation Notification.

v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total Annual Qualified Capacity including the Annual Qualified Capacity associated with the Deactivation Notification is calculated as the product of (a) the Lead Market Participant's total Annual Qualified Capacity including the Annual Qualified Capacity associated with the Deactivation Notification that is the subject of the review and (b) the Internal Market Monitor-simulated Capacity Clearing Price including the Annual Qualified Capacity associated with the Deactivation Notification.

vi. For purposes of subsections iv. and v. above, the Internal Market Monitor-simulated Capacity Clearing Price, not to exceed the Capacity Auction Offer Price Cap, is based on the System-Wide Capacity Demand Curve, Capacity Zone Demand Curves as specified in Section III.15.1, and the supply curve developed from the most recent Annual Capacity Auction.

For purposes of the test performed in this Section III.A.24, the Annual Qualified Capacity of a Lead Market Participant includes the capacity of Capacity Resources that are controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the Annual Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Annual Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.24.6 and all capacity the control of which it has contracted to a third party.

III.A.24.7. Proxy Capacity Offer.

For those deactivations the Internal Market Monitor determines have failed both the conduct test set forth in Section III.A.24.5 and the portfolio benefit test set forth in Section III.A.24.6, the first-year break-even price calculated based on the Internal Market Monitor's reasonable expectations regarding net present value of the resource's expected cash flows, the resource's Capacity Performance Payments, and the resource's opportunity costs, determined in accordance with Section III.A.24.3, shall be used as that resource's Proxy Capacity Offer price. The deactivation determination filing made to the Commission as described in Section III.A.24.9 shall include an explanation of the resource's Proxy Capacity Offer price. Unless the Commission determines otherwise, the ISO shall enter Proxy Capacity Offers into the Capacity Auction pursuant to Section III.15.4.

III.A.24.8. Deactivation Determination Notification.

No later than 90 days after the Deactivation Notification Deadline, the Internal Market Monitor shall provide written notification to the Lead Market Participant that submitted each Deactivation Notification concerning the result of the Internal Market Monitor's conduct test conducted pursuant to Section III.A.24.5.

III.A.24.9. Deactivation Determinations Filing.

No later than 120 days after the Deactivation Notification Deadline, the ISO shall make a filing with the Commission pursuant to Section 205 of the Federal Power Act confidentially describing the determinations made by the Internal Market Monitor with respect to each Deactivation Notification failing the conduct test, including the supporting documentation for each such determination. The filing shall identify to the extent possible the components of the Deactivation Notification which were accepted as justified, and shall also identify to the extent possible the components of the Deactivation Notification which were not justified and which resulted in the Internal Market Monitor identifying the resource as requiring a Proxy Capacity Offer. The deactivation determinations filing shall identify the Proxy Capacity Offer price that, pursuant to Section III.15.4, will be entered into the Annual Capacity Auction on behalf of the Lead Market Participant during the Capacity Commitment Period in question if the Commission accepts the deactivation determinations filing. In the event that no Deactivation Notification failed the conduct test associated with a particular Deactivation Notification Deadline, the filing shall state that outcome.

In the event that a Lead Market Participant elects pursuant to Section II.53 to delay a resource's deactivation for reliability reasons, and elects pursuant to Section II.54.1 to be compensated based on net going forward costs, the deactivation determinations filing shall include a description of the resource's net going forward costs and all supporting materials necessary to arrive at the resource's net going forward costs, including a description of any instances in which the Internal Market Monitor-determined net going forward costs differ from the net going forward costs that may be arrived at based solely on the resource's cost workbook submission.

SECTION III

MARKET RULE 1

APPENDIX F

NET COMMITMENT PERIOD COMPENSATION ACCOUNTING

APPENDIX F

NCPC ACCOUNTING

Table of Contents

NCPC ACCOUNTING

III.F.1. General.

For purposes of NCPC calculations:

a. Effective Offers. An Effective Offer for a Resource is (1) the Supply Offer, Demand Reduction Offer, or Demand Bid used in making the decision to commit the Resource, (2) the Supply Offer, Demand Reduction Offer, or Demand Bid used in making the decision to dispatch the Resource at a Desired Dispatch Point above its Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit, and (3) the Day-Ahead Ancillary Services Offer is subject to the following conditions:

i. The Effective Offer used in making the decision to commit the Resource establishes the parameters used for NCPC calculations, including the quantity and price pairs for output, demand reduction, or consumption up to the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit; the Start-Up Fee, No-Load Fee, or Interruption Cost; and the operating limits.

ii. In the event the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit is increased after the decision to commit the Resource, the energy price parameter for output, demand reduction, or consumption at the Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit used in making the decision to commit the Resource will be applied as the energy price parameter for additional output, demand reduction, or consumption up to the increased Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit.

iii. In the event a Minimum Generation Emergency is declared, the Economic Minimum Limit will be replaced with the Emergency Minimum Limit for purposes of determining the energy price parameter of the Effective Offer.

iv. The Effective Offer takes account of any mitigation applied to the Supply Offer and the Day-Ahead Ancillary Services Offer, whether performed prior to or after the commitment or dispatch decision is made.

v. The Effective Offer takes account of a reduction in the energy price parameter, the Start-Up Fee, the No-Load Fee, or the Interruption Cost in a Supply Offer or Demand Reduction Offer; or an increase in the energy price parameter of a Demand Bid that is made prior to the end of the Resource's Commitment Period.

vi. In the event the ISO approves the Resource's synchronization to the system as a Pool-Scheduled Resource earlier than its scheduled time, the Effective Offer takes account of the lesser of the energy price parameter, the Start-Up Fee and the No-Load Fee in place for the scheduled Commitment Period or the actual early release-for-dispatch time.

vii. A Resource that is online providing synchronous condensing is considered to be in a hot temperature state for the purpose of determining the Start-Up Fee for the Effective Offer when the Resource is requested to switch from synchronous condensing to provide energy.

viii. The Effective Offer takes account of cost verification performed under Sections III.1.8.1 and III.1.9.1.

ix. The energy price parameter of the Effective Offer for a Demand Response Resource is the energy price parameter submitted in the Demand Reduction Offer, even where the Demand Reduction Threshold Price is used to clear the market pursuant to Section III.1.10.1A(e)(ii).

b. Treatment of Self-Schedules.

i. In the Day-Ahead Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to the minimum of the Energy Offer Floor and the Day-Ahead Locational Marginal Price; or, in the case of a Storage DARD, is treated as having a Demand Bid with an energy price parameter for consumption up to its Minimum Consumption Limit equal to the maximum of the Demand Bid Cap and the Day-Ahead Locational Marginal Price. Any amounts (MW) offered or bid above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid.

ii. In the Real-Time Energy Market, a Resource that is committed as a Self-Schedule is treated either: (i) as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to $0/MWh; or (ii) as having a Demand Bid for consumption up to the Minimum Consumption Limit at the Demand Bid Cap. Any amounts (MW) offered above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid. For any hour for which a Resource is dispatched pursuant to Section III.1.10.9(f), the Resource is treated either: (i) as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the requested amount at the Energy Offer

Floor; or (ii) as having a Demand Bid with an energy price parameter for consumption up to the requested amount at the Demand Bid Cap.

iii. If the Resource's Supply Offer contains a Self-Schedule for fewer contiguous hours than its Minimum Run Time, the minimum number of additional hours required to satisfy the Resource's Minimum Run Time will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market. If the Resource is committed for one or more hours immediately prior to and contiguous with the Self-Schedule, the hours of that prior Commitment Period will be counted toward satisfying the Resource's Minimum Run Time before hours subsequent to the Self-Schedule are counted. If the Resource's Supply Offer contains two Self-Schedules separated by less than the Resource's Minimum Down Time, the hours between the two Self-Schedules will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market.

c. Sub-Hourly Intervals. If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

d. Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Minimum Run Time or Minimum Reduction Time Carries Into Second Operating Day. If a Resource that is committed in either (i) the Day-Ahead Energy Market, or (ii) the Reserve Adequacy Analysis prior to the start of the Operating Day must continue to operate across an Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for hour ending 24 of the Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day. If a Resource that is committed during the Operating Day must continue to operate across the Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the second Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day.

e. Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Committed Prior to Day-Ahead Energy Market. If a Resource is committed for an Operating Day prior to the Day-Ahead Energy Market, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the Operating Day at the time of the commitment is used to establish the Effective Offer for the period of the commitment.

f. Eligibility for NCPC Credits When Performing Audits or Facility and Equipment Testing. The Real-Time NCPC Credit calculation for a Resource performing an audit uses the Start-Up Fee, No-Load Fee, Interruption Cost, Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction in the Effective Offer applicable to the Commitment Period during which the audit is conducted, and does not take account of any increases to the Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction that take place in the course of the audit.

Market Participants are not eligible for NCPC Credits when conducting audits or Facility and Equipment Testing under the following conditions:

i. When a Market Participant requests that some hours of the commitment of a Pool-Scheduled Resource be used to satisfy an audit, and the Market Participant has changed the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit for those hours for the purpose of conducting the audit, the Market Participant is not eligible for Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the audit is conducted.

ii. When a Market Participant Self-Schedules a Resource to perform the audit, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the Self-Schedule and is not eligible for Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the audit is conducted.

iii. When a Market Participant requests that an audit be performed that requires the ISO to dispatch the Resource for the audit without advance notice to the Market Participant, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment or Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the audit is conducted.

iv. When an ISO-Initiated Claimed Capability Audit is performed pursuant to III.1.5.1.4, the Market Participant is not eligible for Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the audit is conducted if both of the following are true:

1. the Resource had a summer or winter Seasonal Claimed Capability or Seasonal DR Audit value equal to 0 MW at the beginning of the current Capability Demonstration Year, and

2. the ISO Initiated Claimed Capability Audit is the first Claimed Capability Audit that the Resource performs during that Capability Demonstration Year.

v. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Pool-Scheduled Resource, the Economic Minimum Limit (or Minimum Consumption Limit for a Binary Storage DARD) in place at the time of the commitment decision is used for calculating Real-Time Commitment NCPC Credits and the Market Participant is not eligible for Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.

vi. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Resource that Self-Scheduled, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment and is not eligible for Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.

g. **Coordinated External Transactions are Not Eligible for NCPC and are excluded from NCPC Charges.** Notwithstanding anything to the contrary in this Appendix F, Market Participants are not eligible to receive NCPC Credits for Coordinated External Transactions purchases or sales and shall be excluded from all NCPC Charge calculations under this Appendix F.

h. **Demand Response Resource Credit Calculations.** Where indicated in Section III.F.2, the costs and revenues for a Demand Response Resource, other than those associated with Net Supply or Interruption Costs, are increased by average avoided peak distribution losses.

i. **Following Dispatch Instructions.**

i. For the purpose of allocating NCPC costs, a Resource with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit greater 50 MW is considered to be following a dispatch instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 10% above its Desired Dispatch Point and not less than 10% below its Desired Dispatch Point for each interval in the hour. A Resource with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit less than or equal to 50 MW is considered to be following a Dispatch Instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 5 MW above its Desired Dispatch Point and is not less than 5 MW below its Desired Dispatch Point for each interval in the hour. If the Resource violates this criterion in any interval during the hour, the Resource is considered to be not following Dispatch Instructions for the entire hour.

ii. DNE Dispatchable Generators are considered to be following Dispatch Instructions if the actual output of the DNE Dispatchable Generator is at or below its Do Not Exceed Dispatch Point.

III.F.2. NCPC Credits

III.F.2.1 Day-Ahead Market NCPC Credits

III.F.2.1.1. Eligibility for Credit. A Generator Asset with a Supply Offer, a Demand Response Resource with a Demand Reduction Offer, or a Storage DARD with a Demand Bid that clears the Day-Ahead Energy Market in an hour is eligible for Day-Ahead Market NCPC Credits for the hour.

III.F.2.1.2. Settlement Period. For a Generator Asset, a Demand Response Resource, or a Storage DARD, for purposes of calculating Day-Ahead Market NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day for which a Resource has cleared in the Day-Ahead Energy Market. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator or to or from a Fast Start Demand Response Resource, or any time a DNE Dispatchable Generator's operating characteristics change to or from a Flexible DNE Dispatchable Generator, and the Resource is committed with the changed designation.

III.F.2.1.3. Eligible Quantity. For a Generator Asset, Demand Response Resource, or Storage DARD, the eligible quantity of energy is the amount of energy the Resource clears in the Day-Ahead Energy Market for each hour of the settlement period.

III.F.2.1.3A Hourly Bid. For a Storage DARD, the hourly bid is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each hour of the settlement period.

III.F.2.1.4 Hourly Cost for Energy.

(a) For a Generator Asset, the hourly cost is equal to the energy price parameter for the eligible quantity, the Start-Up Fee and the No-Load Fee as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2.

(b) For a Demand Response Resource, the hourly cost is equal to the energy price parameter for the eligible quantity and the Interruption Cost as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2.

(c) For a Storage DARD, the hourly cost is equal to the Day-Ahead Locational Marginal Price for each hour of the settlement period multiplied by the eligible quantity.

III.F.2.1.4.1 For a Generator Asset or a Demand Response Resource, the Start-Up Fee or Interruption Cost is apportioned equally over the hours from the time the Resource is scheduled to begin its commitment through the end of the Commitment Period during which the Minimum Run Time or Minimum Reduction Time is scheduled to expire.

III.F.2.1.4.2 For a Generator Asset or a Demand Response Resource, when the period of hours over which the Start-Up Fee or Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee or Interruption Cost.

III.F.2.1.4.A Hourly Cost for Day-Ahead Ancillary Services. The hourly cost for Day-Ahead Ancillary Services is equal to the Day-Ahead Ancillary Services Offer prices as reflected in the Effective Offer multiplied by the amount of each award for each hour of the settlement period.

III.F.2.1.5 Hourly Revenue for Energy. For a Generator Asset or a Demand Response Resource, the hourly revenue is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity for the Resource, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price.

III.F.2.1.5.A Hourly Revenue for Day-Ahead Ancillary Services. For a Generator Asset, a Demand Response Resource, or a DARD, the Day-Ahead Ancillary Services hourly revenue is equal to the total Day-Ahead Ancillary Services Market Credit as calculated in Section III.3.2.1(q)(1) for each hour of the settlement period.

III.F.2.1.6 General Credit Calculation. Except as provided in Section III.F.2.1.7 below, the Day-Ahead Market NCPC Credit for a Resource, adjusted as described in III.F.1(h), is equal to:

(a) For a Generator Asset or a Demand Response Resource: the greater of (i) zero, and; (ii) the total hourly cost for Energy and Day-Ahead Ancillary Services for the Resource in all hours of the settlement period, minus the total hourly revenue for Energy and Day-Ahead Ancillary Services for the Resource in all hours of the settlement period, where the costs and revenues of a Demand Response Resource, other than those associated with Interruption Costs, are increased by average avoided peak distribution losses; and

(b) For a Binary Storage DARD: the greater of (i) zero and (ii) the total hourly cost for Energy and Day-Ahead Ancillary Services for the Resource in all hours of the settlement period, minus the total hourly bids in all hours of the settlement period and the total Day-Ahead Ancillary Services hourly revenue.

III.F.2.1.7 Credit Calculation for Fast Start Generators, Flexible DNE Dispatchable Generators, Fast Start Demand Response Resources and Binary Storage DARDs Based on Daily Starts, and for Continuous Storage Generator Assets and Continuous Storage DARDs. If either (1) the number of daily starts for a Fast Start Generator, Flexible DNE Dispatchable Generator, Fast Start Demand Response Resource or Binary Storage DARD is less than the resource's Maximum Number of Daily Starts, or (2) the resource is a Continuous Storage Generator Asset or a Continuous Storage DARD, then the resource's Day-Ahead Market NCPC Credit, adjusted as described in III.F.1(h), is calculated as follows:

(a) For a Fast Start Generator, a Continuous Storage Generator Asset, a Flexible DNE Dispatchable Generator or a Fast Start Demand Response Resource, the Day-Ahead Market NCPC Credit is equal to, for each hour of the settlement period, the greater of (i) zero, and; (ii) the hourly cost for Energy and Day-Ahead Ancillary Services for the Resource in an hour, minus the hourly revenue for Energy and Day-Ahead Ancillary Services for the Resource in that hour.

(b) For a Storage DARD, the Day-Ahead Market NCPC Credit is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the total hourly cost for Energy and Day-Ahead Ancillary Services for the Resource in an hour, minus the total hourly bid for the Resource in that hour and the total Day-Ahead Ancillary Services hourly revenue.

III.F.2.2 Real-Time Energy Market NCPC Credits. Real-Time Energy Market NCPC Credits include a Real-Time Commitment NCPC Credit, a Real-Time Dispatch NCPC Credit and a Real-Time Dispatch Lost Opportunity Cost NCPC Credit. For purposes of this Section III.F.2.2, unless otherwise expressly stated, costs and revenues shall be calculated at a five-minute interval.

III.F.2.2.1 Eligibility for Credit.

(a) Commitment Credits – The following Resources are eligible for Real-Time Commitment NCPC Credits for some or all intervals of the hour: (i) a Generator Asset with a Supply Offer that has been submitted in the Real-Time Energy Market and that has been committed by the ISO; (ii) a Demand Response Resource with a Demand Reduction Offer that has been submitted in the Real-Time Energy Market; or (iii) a Binary Storage DARD with a Demand Bid that has been submitted in the Real-Time Energy Market and that has been committed by the ISO.

(b) Dispatch Credits – The following Resources are eligible for Real-Time Dispatch NCPC Credits for some or all intervals of the hour: (i) a Generator Asset with a Supply Offer that has been submitted in the Real-Time Energy Market; (ii) a Demand Response Resource with a Demand Reduction Offer that has been submitted in the Real-Time Energy Market; (iii) a Storage DARD with a Demand Bid that has been submitted in the Real-Time Energy Market; or (iv) a Storage DARD that has been Postured to increase its consumption. The Real-Time Dispatch NCPC Credit shall be zero, however, if the Generator Asset has provided Regulation during the interval.

(c) Dispatch Lost Opportunity Cost Credits – A Generator Asset with a Supply Offer, a Demand Response Resource with a Demand Reduction Offer, or a Dispatchable Asset Related Demand with a Demand Bid that is committed and able to respond to Dispatch Instructions during the interval is eligible to receive a Real-Time Dispatch Lost Opportunity Cost NCPC Credit; provided, however, that such credit shall be zero if the Generator Asset, Demand Response Resource, or Dispatchable Asset Related Demand has been Postured or has provided Regulation during the interval.

III.F.2.2.2 Real-Time Commitment NCPC Credits

III.F.2.2.2.1. Settlement Period.

(a) For Generator Assets, Demand Response Resources, and Binary Storage DARDs, for purposes of calculating Real-Time Commitment NCPC Credits, a settlement period is a period of one or more contiguous intervals in an Operating Day during which a Resource is operating pursuant to one or more commitments in the Day-Ahead Energy Market or Real-Time Energy Market.

(b) For Generator Assets and Demand Response Resources, a new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, to or from a Flexible DNE Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.

(c) For Generator Assets and Binary Storage DARDs, in the event of an interruption in operation of a Resource, operation will be considered contiguous if the Resource returns to operation in accordance with the original commitment issued prior to the interruption.

III.F.2.2.2.2. Eligible Quantity.

III.F.2.2.2.2.A For a Binary Storage DARD, the eligible quantity for each interval is the amount of energy equal to the lesser of its Economic Dispatch Point for that interval and its Metered Quantity For Settlement for the interval.

III.F.2.2.2.2.1.

(a) For a Generator Asset, the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy equal to the lesser of the Resource's Metered Quantity For Settlement and Economic Dispatch Point for the interval; provided however, that during contiguous pricing intervals in which the Generator Asset's Economic Dispatch Point is higher than it would otherwise be as a result of an offered ramp rate limitation, then the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy for the interval equal to the lesser of: (a) the Generator Asset's Metered Quantity For Settlement; and (b) the greater of: (i) the Generator Asset's expected output level had it reduced its output per its offered ramp rate during the relevant intervals as instructed by the ISO, and (ii) the output level to which the Generator Asset would have been dispatched absent the offered ramp rate limitation.

(b) For a Generator Asset, the eligible quantity for determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit is the lesser of the Resource's Metered Quantity For Settlement and Economic Dispatch Point for the interval, except that Metered Quantity For Settlement is used as the eligible quantity (i) when the Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) when the Resource is ramping from an offline state to be released for dispatch or (iii) after the Resource has been released for shutdown.

III.F.2.2.2.2.2.

(a) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the lesser of the Resource's Metered Quantity For Settlement and its Economic Dispatch Point for the interval; provided however, that during contiguous pricing intervals in which the Demand Response Resource's Economic Dispatch Point is higher than it would otherwise be as a result of an offered ramp rate limitation, then the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy for the interval equal to the lesser of: (a) the Demand Response Resource's Metered Quantity For Settlement; and (b) the greater of: (i) the Demand Response Resource's expected demand reduction had it provided the reduction per its offered ramp rate during the relevant intervals as instructed by the ISO, and (ii) the demand reduction level at which the Demand Response Resource would have been dispatched absent the offered ramp rate limitation.

(b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit is equal to the eligible quantity used to determine interval costs pursuant to (a) above, except that the eligible quantity shall be the Metered Quantity For Settlement if any of the following are true: (i) the Demand Response Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) the Demand Response Resource Notification Time and Demand Response Resource Start-Up Time have not concluded, or (iii) the Demand Response Resource has received an instruction to stop reducing demand.

III.F.2.2.2.3. Interval Cost.

(a) The interval cost for a Generator Asset is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Start-Up Fee and No-Load Fee as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1, III.F.2.2.2.3.2, and III.F.2.2.2.3.3.

(b) The interval cost for a Demand Response Resource is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Interruption Cost as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1 and III.F.2.2.2.3.2, provided that costs shall be set to $0 for the interval when there is a negative demand reduction.

(c) The interval cost for a Binary Storage DARD is the Real-Time Price for the interval multiplied by the eligible quantity. The interval cost is reduced by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval cost is also reduced by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5.

III.F.2.2.2.3.1

(a) For a Generator Asset, the energy cost for an interval excludes the cost of (a) energy produced when the Resource is ramping from an offline state to be released for dispatch and (b) energy produced after the Resource has been released for shutdown.

(b) For a Demand Response Resource, the energy cost for an interval excludes the cost of (a) energy produced prior to the conclusion of the Demand Response Resource Start-Up Time and (b) energy produced after the Demand Response Resource has received an instruction to stop reducing demand.

III.F.2.2.2.3.2

(a) For a Generator Asset, the Start-Up Fee is apportioned equally over the intervals from the time the Generator Asset is released for dispatch through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire, subject to the following conditions:

(i) The Start-Up Fee is reduced in proportion to the number of minutes after 30 the Generator Asset is released for dispatch (measured from the time the Generator Asset was scheduled to be released for dispatch), divided by the time from when the Generator Asset was scheduled to be released for dispatch through the end of the Commitment Period during which the Minimum Run Time was scheduled to expire.

(ii) The Start-Up Fee is excluded from the interval cost calculation if the Generator Asset is synchronized to the system prior to its scheduled synchronization time without the ISO's approval of the Generator Asset's synchronization as a Pool-Scheduled Resource.

(iii) The portion of the Start-Up Fee apportioned to any interval during which the Generator Asset is not online because the Generator Asset has tripped is excluded from the interval cost calculation, except in the event the Generator Asset is not online due to a trip that results from equipment failure involving equipment located on the electric network beyond the low voltage terminals of the Generator Asset's step-up transformer. It is the responsibility of the Lead Market Participant for the Generator Asset to inform the ISO at xtrip@iso-ne.com within 30 days that the trip was the result of such a transmission-related event.

(iv) The Start-Up Fee is not reduced when the Generator Asset has shutdown with the ISO's approval prior to the end of its Commitment Period.

(v) The additional Start-Up Fee for a Generator Asset requested to re-start following a trip is apportioned equally over the remaining intervals of the Commitment Period when the ISO requests a Generator Asset to re-start to complete its Commitment Period.

(vi) When the period of intervals over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.

(b) For a Demand Response Resource, the Interruption Cost is apportioned equally over the intervals from the time the Demand Response Resource Start-Up Time concludes through the end of the Commitment Period during which the Minimum Reduction Time is scheduled to expire, subject to the following conditions:

(i) The Interruption Cost is reduced in proportion to the number of minutes after 30 the Demand Response Resource begins to provide a demand reduction (measured from the conclusion of the Demand Response Resource Start-Up Time), divided by the time from the conclusion of the Demand Response Resource Start-Up Time through the end of the Commitment Period during which the Minimum Reduction Time was scheduled to expire.

(ii) The portion of the Interruption Cost apportioned to any interval during which the Demand Response Resource is not providing a demand reduction because the Demand Response Resource has become unavailable to provide a reduction is excluded from the interval cost calculation.

(iii) The Interruption Cost is not reduced when the Demand Response Resource has stopped reducing demand with the ISO's approval prior to the end of its Commitment Period. When the period of intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.

(iv) When the period of intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.

III.F.2.2.2.3.3. For a Generator Asset for each hour, the No-Load Fee is equally apportioned to each interval in the hour during the period when the Generator Asset is online following its release for dispatch and prior to its release for shutdown. The No-Load Fee is pro-rated for the hour during which the Generator Asset is released for dispatch, the hour during which the Generator Asset is released for shutdown, and any other hour during which the Generator Asset operates for less than 60 minutes.

III.F.2.2.2.3.A Interval Bid. The interval bid for a Binary Storage DARD is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each interval of the settlement period.

III.F.2.2.2.4 Interval Revenue. The interval revenue for a Generator Asset or Demand Response Resource is equal to the Real-Time Price for each interval of the settlement period multiplied by the eligible quantity for the interval. The revenue for an interval is increased by the amount by which the interval revenues in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.4 exceed the interval costs in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.3. The interval revenue is increased by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval revenue is also increased by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5. The revenues when the Generator Asset is ramping from an offline state to be released for dispatch, or during the Demand Response Resource Start-Up Time, are apportioned equally to the intervals of the Minimum Run Time or Minimum Reduction Time.

III.F.2.2.2.4.1. For a Generator Asset, revenues for output up to the Resource's Economic Minimum Limit in a Self-Scheduled interval, calculated as the Real-Time Price multiplied by the output, are excluded from the revenue for the Real-Time Commitment NCPC Credit calculation.

III.F.2.2.2.4.2. For a Demand Response Resource, revenues shall be set to $0 for the interval when the Locational Marginal Price is positive and there is a negative demand reduction.

III.F.2.2.2.5 Credit Calculation for Generator Assets and Demand Response Resources. The Real-Time Commitment NCPC Credit for a Generator Asset or a Demand Response Resource, adjusted as described in III.F.1(h) is equal to:

(a) For the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval revenue for the Resource for the period,

plus,

(b) For each remaining interval of the settlement period following the completion of the Minimum Run Time or Minimum Reduction Time, the greater of ((i) zero, and; (ii) the maximum potential net revenues for the Resource in the period) minus the actual net revenues for the Resource in the period, where

(i) The maximum potential net revenue is the maximum accumulated net interval revenue for operating and then shutting down (or, for a Demand Response Resource, reducing demand and then ceasing to reduce demand) during the period.

(ii) The actual net revenue is the accumulated net interval revenue over the period.

(iii) The net interval revenue is the interval revenues minus interval costs in the period.

III.F.2.2.2.6. [Reserved.]

III.F.2.2.2.7 Credit Calculation for Binary Storage DARDs. The Real-Time Commitment NCPC Credit for a Binary Storage DARD is equal to:

(a) For the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval bid for the Resource for the period,

plus,

(b) For each remaining interval of the settlement period following the completion of the Minimum Run Time, the greater of ((i) zero, and; (ii) the maximum potential net benefit for the Resource in the period) minus the actual net benefit for the Resource in the period, where

(i) The maximum potential net benefit is the maximum accumulated net interval benefit for operating and then shutting down during the period.

(ii) The actual net benefit is the accumulated net interval benefit over the period.

(iii) The net interval benefit is the interval bid minus interval cost in the period.

III.F.2.2.2.8 Resources with Commitment in the Day-Ahead Energy Market (other than Fast Start Generators, Fast Start Demand Response Resources, and Binary Storage DARDs).

(a) For purposes of calculating the interval cost under Section III.F.2.2.2.3, for any hour in which a Resource (other than a Fast Start Generator, Fast Start Demand Response Resource, or Binary Storage DARD) has a commitment in the Day-Ahead Energy Market, the Start-Up Fee, No-Load Fee, Interruption Cost and energy price parameter for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to $0 for the hour. The Start-Up Fee shall not be set to $0 in the case when a Resource re-starts at ISO request following a trip.

(b) For purposes of calculating the interval revenue under Section III.F.2.2.2.4, for any hour in which a Resource (other than a Fast Start Generator, Fast Start Demand Response Resource, or Binary Storage DARD) has a commitment in the Day-Ahead Energy Market, the revenue for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to $0 for the hour if such revenue is less than $0.

(c) Notwithstanding anything to the contrary in this Section III.F.2.2.2, a Generator Asset that cleared in the Day-Ahead Energy Market and performs an audit scheduled by the ISO pursuant to Section III.1.5.2(f) during all or part of its Day-Ahead schedule on a higher-priced fuel than that which formed the basis of the Generator Asset's Supply Offer in the Day-Ahead Energy Market shall receive additional compensation equal to:

i. For the MW quantity equal to the lesser of the Generator Asset's actual metered output and Economic Dispatch Point, the difference between 1) the incremental energy audit costs based on the Supply Offer using the fuel on which the audit was performed and 2) amounts calculated for that same operation as reflected in the greater of the Day-Ahead Supply Offer and the cost-based Reference Levels calculated using the fuel on which the Day-Ahead Supply Offer was based; and

ii. The difference between the No-Load Fee based on the Supply Offer using the fuel on which the audit was performed and the No-Load Fee for that same operation as reflected in the Day-Ahead Supply Offer; and

iii. Any additional Start-Up Fees incurred as a result of performing the audit.

III.F.2.2.3. Real-Time Dispatch NCPC Credits for Generator Assets and Demand Response Resources.

III.F.2.2.3.1 Settlement Period.

(a) Except as provided in Section III.F.2.2.3.1(b), for Generator Assets and Demand Response Resources, for purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement for a Resource are each greater than its Economic Dispatch Point, excluding any period of time when:

i. For a Generator Asset, the generator is ramping from an offline state to be released for dispatch, and after the generator has been released for shutdown, or

ii. For a Demand Response Resource, prior to the conclusion of the Demand Response Start-Up Time and after the Demand Response Resource has received a Dispatch Instruction to stop reducing demand.

(b) For a Continuous Storage Generator Asset associated with an ATRR that has provided Regulation during the interval, a settlement period is an interval when the Desired Dispatch Point is greater than the Economic Dispatch Point.

III.F.2.2.3.2. Eligible Quantity.

III.F.2.2.3.2.1.

(a) For a Generator Asset, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit is the Generator Asset's Economic Dispatch Point for the interval subtracted from the lesser of the Generator Asset's Metered Quantity For Settlement or Desired Dispatch Point for the interval, unless a Continuous Storage Generator Asset is associated with an ATRR that has provided Regulation during the interval, in which case the eligible quantity is the Generator Asset's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.

(b) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit is the Demand Response Resource's Economic Dispatch Point for the interval subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement and its Desired Dispatch Point for the interval.

III.F.2.2.3.2.2.

(a) For a Generator Asset, the eligible quantity for determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit is the Generator Asset's Metered Quantity For Settlement for the interval minus the Generator Asset's Economic Dispatch Point, except that the Generator Asset's Economic Dispatch Point subtracted from the lesser of the Generator Asset's Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval. Notwithstanding the foregoing, if a Continuous Storage Generator Asset is associated with an ATRR that has provided Regulation during the interval, the eligible quantity is the Generator Asset's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.

(b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit equals the Demand Response Resource's Metered Quantity For Settlement for the interval minus the Demand Response Resource's Economic Dispatch Point, except that the Demand Response Resource's Economic Dispatch Point subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval.

III.F.2.2.3.3 Interval Cost. For a Generator Asset or a Demand Response Resource, the interval cost is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer and does not include the Start-Up Fee, the No-Load Fee, or the Interruption Cost.

III.F.2.2.3.4 Interval Revenue. For a Generator Asset or a Demand Response Resource, the interval revenue is equal to the Real-Time Price multiplied by the eligible quantity.

III.F.2.2.3.5. Credit Calculation. For a Generator Asset or a Demand Response Resource, the Real-Time Dispatch NCPC Credit in an interval is equal to the greater of (i) zero and (ii) the interval cost minus the interval revenue for the Resource, adjusted as described in III.F.1(h).

III.F.2.2.4 Real-Time Dispatch NCPC Credits for Storage DARDs

III.F.2.2.4.1 Settlement Period. For purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement are each greater than the Storage DARD's Economic Dispatch Point, unless a Continuous Storage DARD is associated with an ATRR that has provided Regulation during the interval, in which case a settlement period is an interval when the Desired Dispatch Point is greater than the Economic Dispatch Point.

III.F.2.2.4.2 Eligible Quantity. The eligible quantity of energy is equal to the greater of (i) zero and (ii) the Storage DARD's Economic Dispatch Point for the interval subtracted from the lesser of the Storage DARD's Metered Quantity For Settlement or Desired Dispatch Point for the interval, unless a Continuous Storage DARD is associated with an ATRR that has provided Regulation during the interval, in which case the eligible quantity is the DARD's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.

III.F.2.2.4.3 Interval Cost. The interval cost is the Real-Time Price for the interval multiplied by the eligible quantity.

III.F.2.2.4.4 Interval Bid. The interval bid is equal to the energy price parameter for the eligible quantity as reflected in the Demand Bid for each interval of the settlement period.

III.F.2.2.4.5 Credit Calculation. The Real-Time Dispatch NCPC Credit for an eligible Storage DARD in an interval is equal to the greater of: (i) zero, and; (ii) the interval cost minus the interval bid in that interval.

III.F.2.2.5. Real-Time Dispatch Lost Opportunity Cost NCPC Credits

III.F.2.2.5.1. Maximum Net Revenue or Maximum Net Benefit.

(a) For a Generator Asset or a Demand Response Resource, the maximum net revenue during the interval is the Resource's energy revenue at the Economic Dispatch Point, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point, as described in III.F.1(h).

(b) For a Dispatchable Asset Related Demand, the maximum net benefit during the interval is the Resource's energy price parameter for the Economic Dispatch Point as reflected in the Demand Bid, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point.

III.F.2.2.5.2. Actual Net Revenue or Actual Net Benefit.

(a) The actual net revenue for a Generator Asset or Demand Response Resource shall be the sum, adjusted as described in III.F.1(h), of the following two values:

   (i) for a Continuous Storage Generator Asset associated with an ATRR that has provided Regulation during the interval, the energy revenue at the dispatched energy quantity minus the offered energy cost for that quantity; otherwise, the greater of: (1) the energy revenue at the Metered Quantity For Settlement minus the offered energy cost for that quantity and (2) the energy revenue at the dispatched energy quantity minus the offered energy cost for that quantity; and

   (ii) the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.

(b) The actual net benefit for a Dispatchable Asset Related Demand shall be the sum of the following two values:

   (i) for a Continuous Storage DARD associated with an ATRR that has provided Regulation during the interval, the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid minus the offered energy cost for that quantity; otherwise, the greater of: (1) the energy price parameter for the Metered Quantity For Settlement as reflected in the Demand Bid minus the offered energy cost for that quantity and (2) the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid minus the offered energy cost for that quantity; and

(ii) the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.

III.F.2.2.5.3. Credit Calculation. For a Generator Asset, a Demand Response Resource, or a Dispatchable Asset Related Demand, the Real-Time Dispatch Lost Opportunity Cost NCPC Credit is equal to the greater of: (i) zero; and (ii) the Resource's maximum net revenue or benefit for the interval less its actual net revenue or benefit for the interval.

The Dispatch Lost Opportunity Cost NCPC Credit for a Resource for an interval shall be reduced by the amount of any Rapid Response Pricing Opportunity Cost NCPC Credits for which the Resource is eligible for that interval, but shall be no less than zero.

III.F.2.3. Special Case NCPC Credit Calculations

III.F.2.3.1. Day-Ahead External Transaction Import and Increment Offer NCPC Credits

III.F.2.3.1.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction imports or Increment Offers at an External Node are eligible for Day-Ahead External Transaction Import and Increment Offer NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.1.2. Hourly Offer. The Day-Ahead offer for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the offer price.

III.F.2.3.1.3. Hourly Revenue. The Day-Ahead revenue for a pool-scheduled External Transaction import at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, not subject to the credit conditions specified in Section III.3.2.1(q)(4)(ii). For Increment Offers at an External Node, the Day-Ahead revenue at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Locational Marginal Price.

III.F.2.3.1.4. Credit Calculation. A Day-Ahead External Transaction Import and Increment Offer NCPC Credit for an External Transaction import or Increment Offer, for an hour, is equal to any portion of the Day-Ahead offer in excess of the Day-Ahead revenue for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction import or Increment Offer for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction export or Decrement Bid for the same External Node and hour, the Day-Ahead External Transaction Import and Increment Offer NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction import or Increment Offer at the External Node for the hour that is not offset by the amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour. If multiple External Transaction imports or Increment Offers at an External Node are eligible for a Day-Ahead External Transaction Import and Increment Offer NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction imports and Increment Offers will be offset in order from the highest to the lowest-priced transactions or offers.

III.F.2.3.2. Day-Ahead External Transaction Export and Decrement Bid NCPC Credits

III.F.2.3.2.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction exports or Decrement Bids at an External Node are eligible for Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.2.2. Hourly Bid. The Day-Ahead bid for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the bid price.

III.F.2.3.2.3. Hourly Cost. The Day-Ahead cost for a pool-scheduled External Transaction export at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price at the External Node, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price. For Decrement Bids at an

External Node, the Day-Ahead cost at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Locational Marginal Price.

III.F.2.3.2.4. Credit Calculation. A Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for an External Transaction export or Decrement Bid, for an hour, is equal to any portion of the Day-Ahead hourly cost in excess of its Day-Ahead hourly bid for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction export or Decrement Bid for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction import or Increment Offer for the same External Node and hour, the Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour that is not offset by the amount (MW) of the total cleared External Transaction import or Increment Offer at the External Node for the hour. If multiple External Transaction exports or Decrement Bids at an External Node are eligible for a Day-Ahead External Transaction Export and Decrement Bid NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction exports and Decrement Bids will be offset in order from the lowest to the highest-priced transactions or bids.

III.F.2.3.3. Real-Time External Transaction NCPC Credits (Import and Export)

III.F.2.3.3.1. Eligibility for Credit. All Market Participants that submit pool-scheduled External Transactions (import or export) are eligible for Real-Time External Transaction NCPC Credits, with the exception of External Transactions to wheel energy through the New England Control Area.

III.F.2.3.3.2. Eligible Quantity.

(a) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that either (i) did not clear in the Day-Ahead Energy Market, or (ii) cleared in the Day-Ahead Energy Market and the price was subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction.

(b) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that cleared in the Day-Ahead Energy Market and the price was not subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction in excess of the cleared Day-Ahead scheduled transaction amount.

III.F.2.3.3.3. Hourly Offer. The hourly offer for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval offer, which is calculated by multiplying the eligible quantity by the offer price for the interval.

III.F.2.3.3.4. Hourly Revenue. The hourly revenue for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval revenue, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

III.F.2.3.3.5. Hourly Bid. The hourly bid for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval bid, which is calculated by multiplying the eligible quantity by the bid price for the interval.

III.F.2.3.3.6. Hourly Cost. The Real-Time cost for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval cost, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

III.F.2.3.3.7. Credit Calculation. A Real-Time External Transaction NCPC Credit for an External Transaction import for an hour is equal to any portion of the hourly offer in excess of the hourly revenue. A Real-Time External Transaction NCPC Credit for an External Transaction export for an hour is equal to any portion of the hourly cost in excess of the hourly bid.

III.F.2.3.4. [Reserved.]

III.F.2.3.5. Real-Time Synchronous Condensing NCPC Credits

III.F.2.3.5.1. Eligibility for Credit. A Resource that is dispatched as a Synchronous Condenser is eligible for Real-Time Synchronous Condensing NCPC Credits.

III.F.2.3.5.2. Condensing Offer Amount. The condensing offer amount for a Resource is equal to the number of hours that the Resource is dispatched as a Synchronous Condenser in an Operating Day multiplied by the hourly price to condense as specified in the Offer Data for the Resource. For a Resource committed from an offline state to provide synchronous condensing, the condensing offer amount includes the condensing start-up fee as specified in the Offer Data for the Resource. In the event an hourly price to condense or condensing start-up fee is not included in the Offer Data for the Resource for the hours that the Resource is dispatched as a Synchronous Condenser, the value for the parameter will be zero.

III.F.2.3.5.3. Credit Calculation. The Real-Time Synchronous Condensing NCPC Credit for a Resource for an Operating Day is equal to the condensing offer amount for that Operating Day.

III.F.2.3.6. Cancelled Start NCPC Credits

III.F.2.3.6.1. Eligibility for credit. A Pool-Scheduled Generator Asset or Demand Response Resource is eligible for a Cancelled Start NCPC Credit if the ISO cancels its commitment of the Pool-Schedule Resource before a Generator Asset is synchronized to the New England Transmission System, or before a Demand Response Resource has completed its Demand Response Resource Notification Time, except that a Market Participant is not eligible for a credit under the following conditions:

(a) The start is cancelled before the commencement of the Notification Time or the Demand Response Resource Notification Time;

(b) The Resource's Notification Time or Demand Response Resource Notification Time as reflected in the Effective Offer is equal to or greater than 24 hours;

(c) The Generator Asset is synchronized to the New England Transmission System for a Self-Schedule within the period of time equal to the lesser of its Minimum Down Time or 10 hours after receiving the ISO cancelled start order; or

(d) The Generator Asset fails to meet its scheduled synchronization time and the ISO cancelled start order is issued more than two hours after the Resource's scheduled synchronization time.

III.F.2.3.6.2. Credit Calculation. The Cancelled Start NCPC Credit for a Resource is equal to the Start-Up Fee or Interruption Cost reflected in the Effective Offer multiplied by the percentage of the Notification Time or Demand Response Resource Notification Time, as reflected in the Effective Offer, that the Resource completed prior to the ISO cancelled start order, where:

(a) The percentage of Notification Time or Demand Response Notification Time completed is equal to the number of minutes after the start of the Notification Time or Demand Response Notification Time the Resource was cancelled divided by the Notification Time or Demand Response Notification Time, and cannot exceed 100%.

III.F.2.3.7. Hourly Shortfall NCPC Credits

III.F.2.3.7.1. Eligibility for Credit. A Generator Asset, Demand Response Resource, or Binary Storage DARD that is pool-scheduled in the Day-Ahead Energy Market is eligible for Hourly Shortfall NCPC Credits for an hour if the ISO (1) cancels its commitment of a non-Fast Start Generator, a non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator; or (2) does not dispatch a Fast Start Generator, a Fast Start Demand Response Resource, a Binary Storage DARD, or a Flexible DNE Dispatchable Generator for the hour; and (3) either the Generator Asset or Binary Storage DARD is offline and available for operation and the Generator Asset associated with the DARD is not supplying electricity to the grid, or the Demand Response Resource has not been dispatched and is available for operation; except that (4) a Market Participant is not eligible for a credit under the following conditions:

(a) The Resource has been Postured for all or part of the hour;
(b) The Resource is a Limited Energy Resource that has been Postured during a prior hour in the Operating Day; or
(c) The Resource is an Intermittent Power Resource that is not a DNE Dispatchable Generator.

III.F.2.3.7.2. Settlement Period. For purposes of calculating Hourly Shortfall NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is eligible for an Hourly Shortfall NCPC Credit. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, to or from a Flexible DNE Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.

III.F.2.3.7.3. Eligible Quantity. The eligible quantity for each hour of the settlement period is:

(a) zero for a Fast Start Generator, a Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter, the Start-Up Fee and the No-Load Fee of the Supply Offer, or the total of the energy price parameter and the Interruption Cost of the Demand Reduction Offer, in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market for the hour is greater than the total of the corresponding energy price, Start-Up Fee, No Load Fee, and Interruption Cost parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9(e), the Start-Up Fee, No-Load Fee and energy at the Economic Minimum Limit are equal to $0, and (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9(f), the Start-Up Fee and No-Load Fee are equal to $0 and the energy at the requested dispatch level is the Energy Price Floor.

(b) zero for a Binary Storage DARD in the event the energy price parameter in the Demand Bid in the Real-Time Energy Market for the consumption cleared in the Day-Ahead Energy Market for the hour is less than the energy price parameter in the Demand Bid in the Day-Ahead Energy Market for the hour.

i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9 (e), then the energy price at the Minimum Consumption Limit is equal to the Demand Bid Cap, and; (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9 (f), then the energy price at the requested dispatch level for Binary Storage DARDs is the Demand Bid Cap.

(c) the Day-Ahead Economic Minimum Limit or Minimum Reduction for a non-Fast Start Generator, non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter of the Supply Offer or Demand Reduction Offer in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market above the Day-Ahead Economic Minimum Limit or Day-Ahead Minimum Reduction for an hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

and if neither (a) nor (b) nor (c) applies, then;

(d) the minimum of (i) the amount of energy cleared in the Day-Ahead Energy Market for an hour and (ii) the Resource's Economic Maximum Limit, Maximum Reduction, or a Limited Energy Resource limit imposed for the hour in the Real-Time Energy Market.

III.F.2.3.7.4. Credit Calculation (for non-Fast Start Generators, non-Fast Start Demand Response Resources, and non-Flexible DNE Dispatchable Generators). The Hourly Shortfall NCPC Credit for a Resource, other than a Fast Start Generator, a Fast Start Demand Response Resource, a Binary Storage DARD, or a Flexible DNE Dispatchable Generator, adjusted as described in III.F.1(h), is equal to:

(a) the greater of (i) zero and (ii) the total of (the Real-Time Price minus the Day-Ahead Price for an hour, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, multiplied by the Day-Ahead Economic Minimum Limit for the hour or the Day-Ahead Minimum Reduction for the hour) for all hours of the settlement period,

plus

(b) for each hour of the settlement period, for Generator Assets, the greater of (i) zero and (ii) the product of (1) the Real-Time Price minus the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, for an hour and (2) the eligible quantity minus the Day-Ahead Economic Minimum Limit for the hour; or, for Demand Response Resources, the greater of (i) zero and (ii) the product of (1) the Real Time Price minus the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, for an hour and (2) the eligible quantity minus the Day-Ahead Minimum Reduction for the hour.

III.F.2.3.7.5. Credit Calculation (for Fast Start Generators, Fast Start Demand Response Resources and Flexible DNE Dispatchable Generators). The Hourly Shortfall NCPC Credit for a Fast Start Generator, Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and (ii) the Real-Time Price minus the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, for an hour, multiplied by the eligible quantity for the hour, adjusted as described in III.F.1(h).

III.F.2.3.7.6 Credit Calculation (for Binary Storage DARDs). The Hourly Shortfall NCPC Credit for a Binary Storage DARD is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the Day-Ahead Locational Marginal Price minus the Real-Time Price for an hour, multiplied by the eligible quantity for the hour.

III.F.2.3.8. Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability

III.F.2.3.8.1. Eligibility for Credit. A Limited Energy Resource is eligible for real-time posturing NCPC credits for any Operating Day during which the Generator Asset has been Postured, when a request to minimize the as-bid production costs of the Generator Asset has been submitted. For purposes of calculating real-time posturing NCPC credits, the Generator Asset is treated as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Generator Asset was Postured, and if not the Generator Asset is treated as a non-Fast Start Generator. If the Generator Asset is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

III.F.2.3.8.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits for Limited Energy Resources, a settlement period is the period of one or more contiguous hours from the initiation of Posturing through the end of the Operating Day.

III.F.2.3.8.3 Resources Sharing a Single Fuel Source. When Limited Energy Resources that share a fuel source are Postured, for purposes of calculating real-time posturing NCPC credits the energy available to the Postured Generator Assets will be allocated among the Postured Generator Assets sharing the fuel source as indicated by estimates of available energy provided by the Lead Market Participant for each Generator Asset prior to Posturing.

III.F.2.3.8.4. Estimated Replacement Cost of Energy. The estimated replacement cost of energy is (i) the average of the Day-Ahead Locational Marginal Prices for hours ending 3 through 5 in the subsequent Operating Day for a Generator Asset that is part of an Electric Storage Facility, or (ii) the product of the oil index price multiplied by the oil-fired generator proxy heat rate for fuel oil-fired generating units, or (iii) zero for all other Generator Assets.

For fuel oil-fired generators, the oil index price is the ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation, and the oil-fired generator proxy heat rate is the average of the heat rate at Economic Min and the heat rate at Economic Max, where the heat rate at Economic Min is, for a Generator Asset, the average hourly energy price parameter of the Supply Offer at the Generator Asset's Economic Minimum Limit at the time of the Posturing decision divided by the oil index price, and the heat rate at Economic Max is, for a Generator Asset, the average hourly energy price parameter of the Supply Offer at the Generator Asset's Economic Maximum Limit at the time of the Posturing decision divided by the oil index price.

III.F.2.3.8.5. Estimated Revenue. The estimated revenue for a Generator Asset is the optimized energy output multiplied by the Real-Time Price for all hours in the settlement period. The optimized energy output is estimated for each hour by allocating the Postured energy to hours that the Generator

Asset would have operated had it not been Postured based on Real-Time Prices in the Operating Day, subject to the following conditions:

(a) the optimized energy output determination will take account of the Generator Asset's Economic Minimum Limit, and Economic Maximum Limit.
(b) the optimized energy output determination will take account of the estimated avoided cost of replacing energy that is not allocated to any hour and remains available at the end of the Operating Day.
(c) for non-Fast Start Generators, the optimized energy output is calculated for the contiguous hours from the time the Generator Asset is Postured until the available energy is depleted.

III.F.2.3.8.6. Estimated Avoided Replacement Cost. The estimated avoided replacement cost for an Operating Day is the remaining energy that would have been available at the end of the Operating Day had the Generator Asset operated in accordance with the optimized energy output determination in Section III.F.2.3.8.5, plus any increase in the remaining energy resulting from replenishment during the Operating Day after the Generator Asset is Postured, multiplied by the estimated replacement cost of energy.

III.F.2.3.8.7. Actual Revenue. The actual revenue for a Generator Asset is the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the settlement period.

III.F.2.3.8.8. Actual Avoided Replacement Cost. The actual avoided replacement cost for an Operating Day is the actual remaining energy at the end of the Operating Day multiplied by the estimated replacement cost of energy.

III.F.2.3.8.9. Credit Calculation. The real-time posturing NCPC credit for Limited Energy Resources is equal to the greater of (i) zero and (ii) the estimated revenue plus the estimated avoided replacement cost, minus the actual revenue plus the actual avoided replacement cost.

III.F.2.3.9. Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured for Reliability and for Demand Response Resources Postured for Reliability

III.F.2.3.9.1. Eligibility for Credit. Generator Assets (other than Limited Energy Resources) and Demand Response Resources are eligible for real-time posturing NCPC credits for the hours during which the Resource has been Postured.

III.F.2.3.9.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits, a settlement period is an hour during which the Generator Asset or Demand Response Resource is Postured.

III.F.2.3.9.3. Offer Used for Estimated Hourly Revenue and Cost.

(a) For a Generator Asset, the offer parameters used to estimate revenue and cost for an hour for purposes of calculating real-time posturing NCPC credits are:

  (i) Energy Price: the higher of the energy price parameter specified in (1) the Supply Offer for the hour at the time the ISO Postures the Generator Asset, or (2) the Supply Offer for the hour at the start of the hour;

  (ii) Start-Up Fee and No Load Fee: for Generator Assets Postured offline, the Start-Up Fee and No-Load Fee specified in the Supply Offer for the hour at the time the Generator Asset is Postured;

  (iii) for Generator Assets Postured to remain online but reduce output, the Start-Up Fee and No-Load Fee are calculated pursuant to Section III.F.2.2.2.3.

(b) For a Demand Response Resource, the offer parameters used to estimate revenue and cost for an hour for purposes of calculating real-time posturing NCPC credits are:

  (i) Energy Price: the higher of the energy price parameter specified in (1) the Demand Reduction Offer for the hour at the time the ISO Postures the Resource, or (2) the Demand Reduction Offer for the hour at the start of the hour;

  (ii) Interruption Cost: for a Demand Response Resource Postured to a demand reduction of zero MW, the Interruption Cost specified in the Demand Reduction Offer for the hour at the time the Demand Response Resource is Postured; for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MW, the Interruption Cost is calculated pursuant to Section III.F.2.2.2.3.

III.F.2.3.9.4. Estimated Hourly Revenue.

(a) The estimated hourly revenue for a Generator Asset is the optimized energy output multiplied by the Real-Time Price for the hour. The optimized energy output is estimated for each hour by determining where the Generator Asset would have operated had it not been Postured based on Real-Time Prices.

The optimized energy output determination will take account of the energy price parameter of the Supply Offer and the Generator Asset's Economic Minimum Limit and Economic Maximum Limit.

(b) The estimated hourly revenue for a Demand Response Resource is the optimized demand reduction multiplied by the Real-Time Price for the hour, where:

(i) The optimized demand reduction is estimated for each hour by determining where the Demand Response Resource would have operated had it not been Postured based on Real-Time Prices. The optimized demand reduction determination will take account of the energy price parameter of the Demand Reduction Offer and the Demand Response Resource's Minimum Reduction and Maximum Reduction.

III.F.2.3.9.5. Estimated Hourly Cost.

(a) The estimated hourly cost for a Generator Asset is the energy price parameter of the Supply Offer for the optimized energy output for the hour, plus the Start-Up Fee and the No-Load Fee, subject to the following conditions:

(i) For a Fast Start Generator Postured offline, the Start-Up Fee is included in each hour's cost and is not subject to apportionment;

(ii) For a non-Fast Start Generator Postured offline, the Start-Up Fee is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.

(b) The estimated hourly cost for a Demand Response Resource is the energy price parameter of the Demand Reduction Offer for the optimized demand reduction for the hour (where optimized demand reduction is determined pursuant to Section III.F.2.3.9.4(b)), plus the Interruption Cost, subject to the following conditions:

(i) For a Fast Start Demand Response Resource Postured to a demand reduction level of zero MW, the Interruption Cost is included in each hour's cost and is not subject to apportionment;

(ii) For a non-Fast Start Demand Response Resource Postured to a demand reduction of greater than zero MW, the Interruption Cost is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.

(c) A Generator Asset is treated as a Fast Start Generator and a Demand Response Resource is treated as a Fast Start Demand Response Resource for purposes of determining the estimated hourly cost only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator or non-Fast Start Demand Response Resource. If at the time the Resource is Postured the Generator Asset is offline, or the Demand Response Resource has not been dispatched, then its designation as a

Fast Start Generator or Fast Start Demand Response Resource is determined as of the time of the Posturing decision.

III.F.2.3.9.6. Actual Hourly Revenue. The actual hourly revenue for a Generator Asset or a Demand Response Resource is the sum of the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the hour.

III.F.2.3.9.7. Actual Hourly Cost.

(a) The actual hourly cost for a Generator Asset Postured to remain online but reduce output is the sum of the interval cost, which is the energy price parameter of the Supply Offer for the Metered Quantity For Settlement for the interval, plus the Start-Up Fee and No-Load Fee calculated pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Generator Asset Postured offline is zero.

(b) The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MW is the sum of the interval cost, which is the energy price parameter of the Demand Reduction Offer for the Metered Quantity For Settlement for the interval, plus the Interruption Cost calculated pursuant to pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to zero MW is zero.

III.F.2.3.9.8. Credit Calculation. The real-time posturing NCPC credit for a Generator Asset (other than a Limited Energy Resource) or a Demand Response Resource is equal to the greater of (i) zero and (ii) the estimated hourly revenue minus the estimated hourly cost, minus the actual hourly revenue minus actual hourly cost, adjusted as described in III.F.1(h).

III.F.2.3.10. Rapid Response Pricing Opportunity Cost NCPC Credits Resulting from Commitment of Rapid Response Pricing Assets

III.F.2.3.10.1. Eligibility for Credit. During any five-minute pricing interval in which a Rapid Response Pricing Asset is committed by the ISO and not Self-Scheduled, any Resource that is committed and able to respond to Dispatch Instructions during the interval is eligible to receive a Rapid Response Pricing Opportunity Cost NCPC Credit; provided, however, that such credit shall be zero if the Resource is non-dispatchable; the Resource has been Postured or has provided Regulation during the interval; if the Resource is a Settlement Only Resource, or if the Resource is an External Resource or External Transaction.

III.F.2.3.10.2. Economic Net Revenue or Economic Net Benefit.

(a) The economic net revenue for a Generator Asset or Demand Response Resource during the pricing interval is the Resource's optimized feasible energy quantity multiplied by the Real-Time Price, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.

(b) The economic net benefit for a Dispatchable Asset Related Demand during the pricing interval is the Resource's energy price parameter for its optimized feasible energy quantity as reflected in its Demand Bid, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the optimized feasible energy quantity multiplied by the Real-Time Price.

(c) The optimized feasible energy and reserve quantities are determined consistent with the Resource's offer or bid parameters, and are the energy and reserve quantities that maximize the Resource's economic net revenue or economic net benefit for the pricing interval, without changing the Resource's commitment status.

III.F.2.3.10.3. Actual Net Revenue or Actual Net Benefit.

(a) Except as provided in Section III.F.2.3.10.3(b), the actual net revenue for a Generator Asset or Demand Response Resource is the greater of: (i) the actual energy quantity supplied during the pricing interval multiplied by the Real-Time Price, plus the actual reserve quantity supplied during the pricing interval multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities; and (ii) the dispatched energy quantity multiplied by the Real-Time Price, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.

(b) The actual net revenue for a Generator Asset associated with an ATRR that has provided Regulation during the interval is equal to the dispatched energy quantity multiplied by the Real-Time Price, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.

(c) Except as provided in Section III.F.2.3.10.3(d), the actual net benefit for a Dispatchable Asset Related Demand is the greater of: (i) the energy price parameter for the actual energy quantity consumed as reflected in the Demand Bid, plus the actual reserve quantity supplied multiplied by the Real-Time Reserve Clearing Price, minus the actual energy quantity consumed multiplied by the Real-Time Price, and (ii) the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the dispatched energy quantity multiplied by the Real-Time price.

(d) The actual net revenue for a DARD associated with an ATRR that has provided Regulation during the interval is equal to the energy price parameter for the dispatched energy quantity as reflected in the

Demand Bid, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the dispatched energy quantity multiplied by the Real-Time price.

III.F.2.3.10.4. Credit Calculation. The Rapid Response Pricing Opportunity Cost NCPC Credit for a Resource is equal to the greater of: (i) zero; and (ii) the Resource's economic net revenue or economic net benefit for the interval less its actual net revenue or actual net benefit for the pricing interval.

The Rapid Response Pricing Opportunity Cost NCPC Credit for a Resource for an interval shall be reduced by the amount of any Real-Time Dispatch NCPC Credits for which the Resource is eligible for that interval, but shall be no less than zero.

III.F.2.4. Apportionment of NCPC Credits. For purposes of this Section III.F.2.4, any values previously established at the five-minute level shall be aggregated to create hourly values.

Each Day-Ahead Market NCPC Credit calculated pursuant to III.F.2.1.6 is apportioned to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue for all hours in the settlement period.

Each Real-Time Commitment NCPC Credit is apportioned as follows: (i) for the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the portion of the Commitment Period, and (ii) for all remaining intervals of the settlement period, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the period.

Each Hourly Shortfall NCPC Credit for a non-Fast Start Generator, a non-Fast Start Demand Response Resource or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator for energy cleared in the Day-Ahead Market at the Resource's Economic Minimum Limit or Minimum Reduction is apportioned to the hours in which the Real-Time Price exceeds the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, for all hours in the settlement period.

The following NCPC credits are assigned to the hours for which the credit was calculated:

- Day-Ahead Market NCPC Credits calculated pursuant to Section III.F.2.1.7.

- Real-Time Dispatch Lost Opportunity Cost NCPC Credits,
- Real-Time Dispatch NCPC Credits for all Resources,
- Day-Ahead External Transaction Import and Increment Offer NCPC Credits,
- Day-Ahead External Transaction Export and Decrement Bid NCPC Credits,
- Real-Time External Transaction NCPC Credits,
- Hourly Shortfall NCPC Credits for Fast Start Generators, Fast Start Demand Response Resources, Binary Storage DARDs and Flexible DNE Dispatchable Generators,
- Hourly Shortfall NCPC Credits for non-Fast Start Generators, non-Fast Start Demand Response Resources, and DNE Dispatchable Generators that are not Flexible DNE Dispatchable Generators for energy cleared in the Day-Ahead Energy Market above the Resource's Economic Minimum Limit or Minimum Reduction, and
- Rapid Response Pricing Opportunity Cost NCPC Credits as described in Section III.F.2.3.10.

III.F.2.5. NCPC Credit Designation for Purposes of NCPC Cost Allocation. Each hourly credit for Day-Ahead Market NCPC Credits, Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, Day-Ahead External Transaction Import and Increment Offer NCPC Credits, Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, Real-Time External Transaction NCPC Credits, Hourly Shortfall NCPC Credits, and Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured For Reliability and Demand Response Resources Postured For Reliability, and each daily credit for Real-Time Synchronous Condensing NCPC Credits, Cancelled Start NCPC Credits, Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability, and Rapid Response Pricing Opportunity Cost NCPC Credit is designated as first contingency, second contingency, voltage (VAR), distribution (SCR), ISO initiated audits and Minimum Generation Emergency consistent with the reason provided by the ISO when issuing a Dispatch Instruction for the Resource. If there is more than one reason provided by the ISO when issuing the Dispatch Instruction, the NCPC Credits are divided equally for purposes of the above designations. With the exception of Day-Ahead External Transaction Import and Increment Offer NCPC Credits and Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, the hourly credits are summed to determine the total credits for each NCPC Charge category for a day.

III.F.3. Charges for NCPC

III.F.3.1. Cost Allocation.

III.F.3.1.1 Day-Ahead Market NCPC Cost Allocation. NCPC costs for the Day-Ahead Energy Market are allocated and charged as follows:

(a) The total NCPC cost for the Day-Ahead Energy Market associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

(b) The total NCPC cost for the Day-Ahead Energy Market for resources designated as Special Constraint Resources in the Day-Ahead Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

(c) The total NCPC cost for the Day-Ahead Energy Market for resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.

(d) For each External Node, the total NCPC cost for Day-Ahead External Transaction Import and Increment Offer NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Load Obligations at the External Node for the hour.

(e) For each External Node, the total Day-Ahead External Transaction Export and Decrement Bid NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Generation Obligations at the External Node for the hour.

(f) All remaining NCPC costs for the Day-Ahead Market (except the NCPC costs for Storage DARDs) are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub).

(g) All remaining NCPC costs for the Day-Ahead Energy Market associated with Storage DARDs are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub) excluding Day-Ahead Load Obligations associated with Storage DARDs.

III.F.3.1.2. Real-Time Energy Market NCPC Cost Allocation. NCPC costs for the Real-Time Energy Market are allocated and charged as follows, subject to the conditions in Section III.F.3.1.3:

(a) The total NCPC cost for the Real-Time Energy Market associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are allocated and charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

(b) The total NCPC cost for the Real-Time Energy Market for resources designated as Special Constraint Resources in the Real-Time Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

(c) The total ISO initiated audit NCPC cost for resources performing an ISO initiated audit is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.

(d) The total NCPC cost for resources being Postured in the Real-Time Energy Market is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.

(e) The total NCPC cost for Rapid Response Pricing Opportunity Cost NCPC Credit during pricing intervals in which one or more Rapid Response Pricing Asset is committed in the Real-Time Energy Market (and not Self-Scheduled) is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.

(f) The total NCPC cost for the Real-Time Energy Market for resources identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.

(g) Total Minimum Generation Emergency Credits within a Reliability Region are allocated and charged hourly to Market Participants based on each Market Participant's pro rata share of Real-Time Generation Obligations, and positive Real-Time Demand Reduction Obligations, excluding that portion of a Market Participant's Real-Time Generation Obligation and Real-Time Demand Reduction Obligation within a Reliability Region that is eligible for a Real-Time Dispatch NCPC Credit pursuant to Section III.F.2.2.3 during a Minimum Generation Emergency.

(h) The total NCPC cost for Real-Time Dispatch Lost Opportunity Cost NCPC Credits is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.

(i) All remaining NCPC costs for the Real-Time Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of the absolute values of a Market Participant's (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day (excluding certain positive Real-Time Load Obligation Deviations as described in Section III.F.3.1.3(d)); (ii) generation deviations for Pool-Scheduled Resources not following Dispatch Instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following Dispatch Instructions, and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following Dispatch Instructions, including External Resources, in MWhs during the Operating Day; (iii) demand reduction deviations for Pool-Scheduled Demand Response Resources not following Dispatch Instructions; and (iv) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day. The Real-Time deviations calculation is specified in greater detail in Section III.F.3.2.

III.F.3.1.3 Additional Conditions for Real-Time Energy Market NCPC Cost Allocation.

(a) If a Generator Asset has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.

(b) If a Demand Response Resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the resource should not be dispatched in order to avoid a Minimum Generation Emergency, the Market Participant will be responsible for all Real-Time Demand Reduction Obligation Deviation charges, but will not incur related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.

(c) Any difference between the actual consumption (Real-Time Load Obligation) of a DARD and the DARD's Demand Bids that clear in the Day-Ahead Energy Market that result from operation in accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation for the purpose of allocating costs for Real-Time Energy Market NCPC Credits.

(d) In any hour during which a Capacity Scarcity Condition occurs or ISO New England Operating Procedure No. 4 or ISO New England Operating Procedure No. 7 are implemented, any NCPC Charges that would have been allocated pursuant to Section III.F.3.2 to net positive Real-Time Load Obligation Deviations in an affected Load Zone (and related portion of adjacent External Nodes) are instead allocated and charged to Market Participants based on their pro rata share of the sum of their Real-Time Load Obligation (excluding Real-Time Load Obligations associated with a Postured Dispatchable Asset Related Demand Resource) in all the affected Load Zones and (and related portion of adjacent External Nodes) during the affected hour(s). For purposes of this calculation, the ISO shall apportion any Real-Time Load Obligations and Real-Time Load Obligation Deviations at an External Node equally among the Load Zones to which the External Node is interconnected.

III.F.3.2 Market Participant Share of Real-Time Deviations for Real-Time Energy Market NCPC Credits.

Each Market Participant's pro-rata share of the Real-Time deviations for Real-Time Energy Market NCPC Credits is the following:

(a) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead Energy Market MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead Energy Market MWh or less than or equal to 5 MWh, then deviation = 0.

(b) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered output – cleared Day-Ahead Energy Market MWh) or (actual metered output – Real-Time Economic Minimum Limit) or (Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead Energy Market MWh or less than or equal to 5 MWh, then deviation = 0.

(c) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

plus,

(d) for each Pool-Scheduled Generator Asset and Continuous Storage Generator Asset:

(i) If the Generator Asset is not following Dispatch Instructions, has cleared the Day-Ahead Energy Market, has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output − Desired Dispatch Point) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

(ii) If the Generator Asset is not following Dispatch Instructions, has cleared the Day-Ahead Energy Market, has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – cleared Day-Ahead MWh) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead Energy Market MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

(e) for each Pool-Scheduled Demand Response Resource:

(i) If the Demand Response Resource is being dispatched, is not following Dispatch Instructions, has cleared in the Day-Ahead Energy Market, and has not been ordered to stop reducing demand for reliability purposes: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction − Desired Dispatch Point) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

(ii) If the Demand Response Resource is unavailable and has cleared in the Day-Ahead Energy Market: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction – cleared Day-Ahead MWh) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead Energy Market MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

(f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation,

where

(i) each Market Participant's Real-Time Load Obligation Deviation for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations (including the Hub), and

(ii) for purposes of calculating a Participant's Real-Time Load Obligation Deviation under this sub-section (e), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and

(iii) External Transaction sales curtailed by the ISO are omitted from this calculation.

plus,

(g) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation,

where

(i) each Market Participant's Real-Time Generation Obligation Deviation at External Nodes for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes, and

(ii) for purposes of calculating a Participant's Real-Time Generation Obligation Deviation under this sub-section (f), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and

(iii) External Transaction purchases curtailed by the ISO are omitted from this calculation.

plus,

(h) the absolute value of the total over all Locations of the Market Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

III.F.3.3 Local Second Contingency Protection Resource NCPC Charges.

Each Market Participant's pro-rata share of the cost for Day-Ahead Market NCPC Credits and Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection is based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region, excluding Real-Time Load Obligations associated with Storage DARDs subject to the following conditions:

(a) The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating a Market Participant's pro-rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

(b) For hours in which there is an NCPC cost for a resource providing Local Second Contingency Protection and ISO is selling Emergency Energy to an adjacent Control Area, the scheduled amount of Emergency Energy at the applicable External Node will be included in the calculation of a Market Participant's pro rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection as if the Emergency Energy sale were a Real-Time Load Obligation within each affected Reliability Region. The pro rata share calculated for the Emergency Energy transaction shall be included in the charges under an agreement for purchase and sale of Emergency Energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency Energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

External Node Common Name	Associated Transmission Facilities	Reliability Region(s)	Allocator
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390/3016) tie line	Maine	100% to Maine
HQ Phase I/II External Node	HQ-Sandy Pond 3512 & 3521 Lines	West Central Massachusetts	100% to West Central Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-7 Line) Hoosick- Bennington Line (K-6 Line) Rotterdam – Bearswamp Line (E205W Line) Alps – Berkshire Line (393Line) Pleasant Valley – Long Mountain Line (398 Line)	Vermont, Vermont Vermont West Central Massachusetts West Central Massachusetts Connecticut	Allocated proportionally to the Vermont, West Central Massachusetts and Connecticut Reliability Regions based on the Normal Limits as described in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
NY NNC External Node	Northport-Norwalk Harbor (601,602 and 603 Lines)	Connecticut	100% to Connecticut
NY CSC External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(c) For each month, the ISO performs an evaluation of total Local Second Contingency Protection Resource NCPC Charges for each Reliability Region. If, for any Reliability Region, the magnitude of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph c, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency Energy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a Storage DARD.

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ > .06 X Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$

Condition 2 – is the Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ > 2 X Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\text{\%}}$ $_{\text{(Reliability Region)}}$

Where:

Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) divided by the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ equals the sum of the prior 12 months' values, not including the current month, of Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ divided by 12. (For the purposes of other calculations which include the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$, a value of .001 will be substituted for any Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ is triggered.

(ii) Determination of the portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated –

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated = Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ X Min (Condition 1 Rate $_{\text{(Reliability Region, month)}}$, Condition 2 Rate $_{\text{(Reliability Region, month)}}$)

Where:

Condition 1 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus .06 times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Condition 2 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus 2 times the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\text{\% (Reliability Region)}}$ times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

(iii) Determination of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

(Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ / Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

(Regional Network Load $_{\text{(Transmission Customer, Reliability Region, month)}}$ / Regional Network Load $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Regional Network Load $_{\text{(Reliability Region, month)}}$ equals:

The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

Regional Network Load $_{\text{(Customer, Reliability Region, month)}}$ equals:
The Transmission Customer's monthly MWh of Regional Network Load in the Reliability Region.

III.F.4. NCPC Reporting

III.F.4.1. Zonal NCPC Report. Beginning January 2019, for each month, no later than 20 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating the aggregate dollar amount of NCPC Credits by category paid to the resources located in each Load Zone for each day during that month.

III.F.4.2. Resource-Specific NCPC Report. Beginning January 2019, for each month, no later than 90 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating the name of each resource that received NCPC

Credits for that month and the total dollar amount of NCPC Credits that each of those resources received for that month.

III.F.4.3. Operator-Initiated Commitment Report. Beginning January 2019, for each month, no later than 30 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating each resource commitment made during that month after the Day-Ahead Energy Market for a reason other than minimizing the total production costs of serving load. For each such commitment, the report shall include the start time, the Economic Maximum Limit or Maximum Reduction of the committed resource, the Load Zone in which the committed resource is located, and the reason for the commitment.

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied Supplied Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: "Pre-scheduling" as specified in Section III.1.9, "Scheduling" as specified in III.1.10, and "Dispatch" as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 [Reserved.]

III.1.3.2 [Reserved.]

III.1.3.3 [Reserved.]

III.1.4 Requirements for Certain Transactions.

III.1.4.1 ISO Settlement of Certain Transactions.

The ISO will settle, and act as Counterparty to, the transactions described in Section III.1.4.2 if the transactions (and their related transactions) conform to, and the transacting Market Participants comply with, the requirements specified in Section III.1.4.3.

III.1.4.2 Transactions Subject to Requirements of Section III.1.4.

Transactions that must conform to the requirements of Section III.1.4 include: Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as "Section III.1.4 Transactions," and individually as a "Section III.1.4 Transaction." Transactions that conform to the standards are referred to collectively as "Section III.1.4 Conforming Transactions," and individually as a "Section III.1.4 Conforming Transaction."

III.1.4.3 Requirements for Section III.1.4 Conforming Transactions.

(a) To qualify as a Section III.1.4 Conforming Transaction, a Section III.1.4 Transaction must constitute an exchange for an off-market transaction (a "Related Transaction"), where the Related Transaction:

(i) is not cleared or settled by the ISO as Counterparty;

(ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

(iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and

(iv) is not contingent on either party to carry out the Section III.1.4 Transaction.

(b) In addition, to qualify as a Section III.1.4 Conforming Transaction:

(i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;

(ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and

(iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.

(c) As further requirements:

(i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and

(ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

(a) The following types of Claimed Capability Audits may be performed:

(i) An Establish Claimed Capability Audit establishes the Generator Asset's ability to respond to ISO Dispatch Instructions and to maintain performance at a specified output level for a specified duration.

(ii) A Seasonal Claimed Capability Audit determines a Generator Asset's capability to perform under specified summer and winter conditions for a specified duration.

(iii) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.

(iv) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value or the Demand Response Resource's Seasonal DR Audit value.

(b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.

(d) The Claimed Capability Audit value for steam turbine assets with steam exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.

(e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

(a) An Establish Claimed Capability Audit may be performed only by a Generator Asset.

(b) The time and date of an Establish Claimed Capability Audit shall be unannounced.

(c) For a newly commercial Generator Asset:

(i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:

1. Non-intermittent daily cycle hydro;
2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
3. Intermittent Generator Assets

(ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.

(d) For Generator Assets with an Establish Claimed Capability Audit value:

(i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.

(ii) An Establish Claimed Capability Audit shall be performed within five Business Days of the date of the request.

(iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(e) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset.

(f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.

(g) To conduct an Establish Claimed Capability Audit, the ISO shall:

(i) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.

(h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

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

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

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

III.1.5.1.3. Seasonal Claimed Capability Audits.

(a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset.

(b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:

- (i) Non-intermittent daily hydro; and
- (ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).

(c) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset's Seasonal Claimed Capability Audit obligation.

(d) Except as provided in Section III.1.5.1.3(n) below, a summer Seasonal Claimed Capability Audit must be conducted:

- (i) At least once every Capability Demonstration Year;
- (ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.

(e) A winter Seasonal Claimed Capability Audit must be conducted:

(i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:

(1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.

(2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.

(ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.

(f) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset for the audit time period and submitting to the ISO operational data that meets the following requirements:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.

(g) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(h) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.

(i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2

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

(k) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;

(ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and

(iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.

(l) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;

(ii) Retain the current Seasonal Claimed Capability Audit value for the season; and

(iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.

(m) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal

Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

(n) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:

(i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(f).

(ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.

(iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.

(iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(d)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.

(v) This Section III.1.5.1.3(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

(o) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.3(j).

III.1.5.1.3.1 Seasonal DR Audits.

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

(b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.

(c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of April through November;

(d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of December through March.

(e) A Seasonal DR Audit may be performed either:

(i) At the request of a Market Participant as described in subsection (f) below; or

(ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.

(f) If a Market Participant requests a Seasonal DR Audit:

(i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.

(ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.

(iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DR Audit.

(iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.

(iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

(h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.

(i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.

(j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.

(k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.

(l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.

(m) The Seasonal DR Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.

(n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.

(o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

(a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.

(b) An ISO-Initiated Claimed Capability Audit value shall replace either the summer or winter Seasonal DR Audit value for a Demand Response Resource and shall replace both the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:

(i) The Establish Claimed Capability Audit values for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.

(ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.

(c) If for a Generator Asset a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.

(d) The audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:

(i) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit or the Demand Response Resource to its Maximum Reduction.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) For Generator Assets, begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.

(iv) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

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

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

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

III.1.5.2 ISO-Initiated Parameter Auditing.

(a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide energy or reserves.

(b) Generator audits shall be performed using the following methods for the relevant parameter:

(i) **Economic Maximum Limit**. The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.

(ii) **Manual Response Rate**. The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.

(iii) **Start-Up Time**. The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.

(iv) **Notification Time**. The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.

(v) **CLAIM10**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(vii) **Automatic Response Rate**. The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.

(viii) **Dual Fuel Capability**. A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).

(c) Demand Response Resource audits shall be performed using the following methods:

(i) **Maximum Reduction**. The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.

(ii) **Demand Response Resource Ramp Rate**. The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.

(iii) **Demand Response Resource Start-Up Time**. The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.

(iv) **Demand Response Resource Notification Time**. The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.

(v) **CLAIM10**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(d) To conduct an audit based upon historical data, the ISO shall:

(i) Obtain data through random sampling of generator or Demand Response Resource performance in response to Dispatch Instructions; or

(ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to Dispatch Instructions.

(e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.

(f) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:

(i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.

(ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five Business Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.

(g) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer or other operating parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.

(h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:

(i) The Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:

1. Provide an explanation of the discrepancy;
2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
3. Indicate the timeline for completing the restoration; and
4. Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.

(ii) The ISO shall:

1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;
2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.5.3 Reactive Capability Audits.

(a) Two types of Reactive Capability Audits may be performed:

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

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

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

(c) Unless otherwise directed by the ISO, Reactive Resources that are required to perform Reactive Capability Audits shall perform both a lagging Reactive Capability Audit and a leading Reactive Capability Audit.

(d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.

(e) The Reactive Capability Audit value of a Reactive Resource shall reflect any limitations based upon the interdependence of common elements between two or more Reactive Resources such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.

(g) Reactive Capability Audits shall be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Reactive Resource to conduct Reactive Capability Audits more often than every five years if:

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

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

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

(h) A Lead Market Participant or Transmission Owner may request a waiver of the requirement to conduct a Reactive Capability Audit for its Reactive Resource. The ISO, at its sole discretion, shall determine whether and for how long a waiver may be granted.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

III.1.6.4 ISO New England Manuals and ISO New England Administrative Procedures.

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission's regulations.

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 Transmission Constraint Penalty Factors.

In the Day-Ahead Energy Market, the Transmission Constraint Penalty Factor for an interface constraint is $10,000/MWh and the Transmission Constraint Penalty Factor for all other transmission constraints is $30,000/MWh. In the Real-Time Energy Market, the Transmission Constraint Penalty Factor for any transmission constraint is $30,000/MWh. Transmission Constraint Penalty Factors are not used in calculating Locational Marginal Prices.

III.1.7.6 Scheduling and Dispatching.

(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch. The ISO shall use a joint optimization process to serve Day-Ahead Market energy requirements and Day-Ahead Ancillary Services requirements, as described in Section III.1.10.8(a).

(b) [Reserved].

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 LMP-Based Energy Pricing.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the limitations and procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.9 Real-Time Reserve Prices.

The price paid by the ISO for the provision of Real-Time Operating Reserve in the New England Markets will reflect Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.9A Day-Ahead Ancillary Services Prices.

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

III.1.7.10 Other Transactions.

Market Participants may enter into internal bilateral transactions and External Transactions for the purchase or sale of energy or other products to or from each other or any other entity, subject to the obligations of Market Participants to make resources with a Capacity Supply Obligation available for dispatch by the ISO. External Transactions that contemplate the physical transfer of energy or obligations to or from a Market Participant shall be reported to and coordinated with the ISO in accordance with this Market Rule 1 and the ISO New England Manuals.

III.1.7.11 Seasonal Claimed Capability of a Generating Capacity Resource.

(a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.

(b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.

(c) The Seasonal Claimed Capability of a Generator Asset is:

(i) Based upon review of historical data for non-intermittent daily cycle hydro.

(ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.

(iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:

a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.

b. For a Generator Asset that is off-line and not available for commitment shall be zero.

c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.

(iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

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

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

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

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

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and zonal Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 Ramping.

A Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to potential referral under Section III.A.19.

III.1.7.19 Real-Time Reserve Designation.

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

III.1.7.19.1 Eligibility.

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

(1) The Resource must be a Dispatchable Resource located within the metered boundaries of the New England Control Area and capable of receiving and responding to electronic Dispatch Instructions.

(2) The Resource must not be part of the first contingency supply loss.

(3) The Resource must not be designated as constrained by transmission limitations.

(4) The Resource's Operating Reserve, if activated, must be sustainable for at least one hour from the time of activation. (This eligibility requirement does not affect a Resource's obligation to follow Dispatch Instructions, even after one hour from the time of activation.)

(5) The Resource must comply with the applicable standards and requirements for provision and dispatch of Operating Reserve as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19.2 Calculation of Real-Time Reserve Designation.

III.1.7.19.2.1 Generator Assets.

III.1.7.19.2.1.1 On-line Generator Assets.

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

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

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

(c) **Thirty-Minute Operating Reserve.** For an on-line Generator Asset, Thirty-Minute Operating Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within thirty minutes given its Manual Response Rate (and in no case greater than its Economic Maximum Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (b) above.

III.1.7.19.2.1.2 Off-line Generator Assets.

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

(a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.

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

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

III.1.7.19.2.2 Dispatchable Asset Related Demand.

III.1.7.19.2.2.1 Storage DARDs.

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

(b) **Ten-Minute Non-Spinning Reserve.** For a Storage DARD, Ten-Minute Non-Spinning Reserve shall be zero.

(c) **Thirty-Minute Operating Reserve.** For a Storage DARD, Thirty-Minute Operating Reserve shall be zero.

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

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

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

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

III.1.7.19.2.3 Demand Response Resources.

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

III.1.7.19.2.3.1 Dispatched.

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

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

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

III.1.7.19.2.3.2 Non-Dispatched.

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

(a) **Ten-Minute Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Spinning Reserve shall be zero.

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

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

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO Resources that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output, consumption, or demand reduction levels of Generator Assets, DARDs, or Demand Response Resources, change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, equipment is operated with control equipment functioning as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands required by the ISO New England Operating Documents, including but not limited to the Market Participant's ability to procure fuel and physical limitations that could reduce Resource output or demand reduction capability for the pertinent Operating Day.

III.1.7.21 SATOA Participation in Markets: A Node will be established for each SATOA. A Market Participant's market activity, transactions, and actions taken at a SATOA's Node and a SATOA's participation in the New England Markets shall be limited to those necessary to consume or inject energy from or to PTF for any period, magnitude, and duration identified as necessary to: (1) address the applicable system needs or provide the transmission function for which the SATOA was selected as the preferred solution; or (2) as specified in the ISO New England Operating Documents, avoid or mitigate Load Shedding after all available Dispatchable Resources that can effectively provide relief to avoid or mitigate the Load Shedding have been dispatched.

III.1.8 Day-Ahead Ancillary Services and Forecast Energy Requirement.

III.1.8.1 Day-Ahead Ancillary Services Offers.

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

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

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

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

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

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

III.1.8.2 Day-Ahead Ancillary Services Strike Price.

(a) For each hour of the Operating Day, the ISO shall specify the Day-Ahead Ancillary Services Strike Price in $/MWh. The value of the Day-Ahead Ancillary Services Strike Price represents an amount that is the greater of the values calculated in accordance with subsections (1) and (2) below:

(1) the greater of (i) $10/MWh greater than a forecast of the expected hourly Real-Time Hub Price for such hour of the Operating Day and (ii) zero; and

(2) a floor value derived in accordance with subsection (c) below.

(b) The value calculated in subsection (a)(1) above shall be based on a publicly-available forecasting algorithm developed by the ISO. The ISO shall describe the publicly-available forecasting algorithm to Market Participants and shall periodically review and assess the efficacy of the forecasting algorithm. The ISO shall notify stakeholders of any potential revisions to the ISO's forecasting algorithm prior to implementing such revisions.

(c) The floor value in subsection (a)(2) above shall be determined daily based on the marginal cost of supplying energy by an efficient, distillate-fired combustion turbine generator, reflecting regional emissions costs and the lowest-priced distillate fuel available. The ISO shall describe to Market Participants the heat rate, emissions cost, and fuel prices that it uses to determine the value in subsection (a)(2).

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

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

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

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

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

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

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

III.1.8.4 Forecast Energy Requirement Demand Quantity.

For each hour of the Operating Day, the Forecast Energy Requirement Demand Quantity shall be:

(1) the ISO forecast for the total load in the New England Control Area produced pursuant to Section III.1.10.1A(h) of this Market Rule 1, less

(2) the greater of (i) the forecast of front-of-the-meter dispatchable wind and solar resources' total real-time energy supply, as adjusted for any expected operating conditions, less the total energy supply and ancillary services from such resources forecast to clear in the Day-Ahead Market and (ii) zero.

III.1.9 Pre-scheduling.

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

III.1.9.1.1 Cost Verification of Resource Offers.

The incremental energy values of Supply Offers and Demand Response Resources above $1,000/MWh for any Resource other than an External Resource are subject to the following cost verification requirements. Unless expressly stated otherwise, cost verification is utilized in all pricing, commitment, dispatch and settlement determinations. For purposes of the following requirements, Reference Levels are calculated using the procedures in Section III.A.7.5 for calculating cost-based Reference Levels.

(a) If the incremental energy value of a Resource's offer is greater than the incremental energy Reference Level value of the Resource, then the incremental energy value in the offer is replaced with the greater of the Reference Level for incremental energy or $1,000/MWh.

(b) For purposes of the price calculations in Sections III.2.5 and III.2.7A, if the adjusted offer calculated under Section III.2.4 for a Rapid Response Pricing Asset is greater than $1,000/MWh (after the incremental energy value is evaluated under Section III.1.9.1.1(a) above), then verification will be performed as follows using a Reference Level value calculated with the adjusted offer formulas specified in Section III.2.4.

(i) If the Reference Level value is less than or equal to $1,000/MWh, then the adjusted offer for the Resource is set at $1,000/MWh;

(ii) If the Reference Level value is greater than $1,000/MWh, then the adjusted offer for the Resource is set at the lower of the Reference Level value and the adjusted offer.

III.1.9.1.2 Offer and Bid Caps.

(a) For purposes of the price calculations described in Section III.2 and for purposes of scheduling a Resource in the Day-Ahead Energy Market in accordance with Section III.1.7.6 following the commitment of the Resource, the incremental energy value of an offer is capped at $2,000/MWh.

(b) Demand Bids shall not specify a bid price below the Energy Offer Floor or above the Demand Bid Cap.

(c) Supply Offers and Demand Reduction Offers shall not specify an offer price (for incremental energy) below the Energy Offer Floor.

(d) External Transactions shall not specify a price below the External Transaction Floor or above the External Transaction Cap.

(e) Increment Offers and Decrement Bids shall not specify an offer or bid price below the Energy Offer Floor or above the Virtual Cap.

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each Generator Asset as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline and shall remain in effect unless otherwise modified in accordance with Section III.1.10.9. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement the Day-Ahead Market and a Real-Time Energy Market.

(b) The Day-Ahead Market shall enable Market Participants to purchase and sell energy and sell ancillary services through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of Generator Assets or Demand Response Resources with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers or Demand Reduction Offers.

III.1.10.1A Energy and Day-Ahead Ancillary Services Market Scheduling.

Market Participants may submit offers and bids in the Day-Ahead Market until 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) **Locational Demand Bids –** Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the applicable Day-Ahead Price, (ii) hourly schedules for Resources Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the Demand Bid Cap and Virtual Cap.

(b) **External Transactions –** All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) In the Day-Ahead Energy Market, the offer prices for all Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) In the Day-Ahead Energy Market, the offer prices for all Self-Scheduled External Transaction sales at the applicable External Node shall be set equal to the External Transaction Cap;

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(c) **Generator Asset Supply Offers –** Market Participants selling into the New England Markets from Generator Assets may submit Supply Offers for the supply of energy for the following Operating Day.

Such Supply Offers:

(i) Shall specify the Resource and Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) If based on energy from a Generator Asset internal to the New England Control Area, may specify, for Supply Offers, a Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee may vary on an hourly basis;

(iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual-fuel Generator Assets in Section III.A.3 of Appendix A;

(iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;

(v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply

Offer, with regard to operating limits, shall specify changes, including to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource (except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and

(vi) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.

(d) DARD Demand Bids – Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

(i) Shall specify the Dispatchable Asset Related Demand and Blocks (price and Energy quantity pairs) for each hour of the Operating Day for each Dispatchable Asset Related Demand offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) Shall constitute an offer to submit the Dispatchable Asset Related Demand to the ISO for commitment and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes, including to the Maximum Consumption Limit and Minimum Consumption Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource;

(iii) Shall specify a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit; and

(iv) Shall, in the case of a Demand Bid from a Storage DARD, also meet the requirements specified in Section III.1.10.6.

(e) **Demand Response Resource Demand Reduction Offers –** Market Participants selling into the New England Markets from Demand Response Resources may submit Demand Reduction Offers for the supply of energy for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource to the ISO for commitment and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The prices and demand reduction quantities may vary on an hourly basis.

(ii) Shall not specify a price that is below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

(iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.

(iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.

(v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.

(vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets.

(vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource.

(f) **Demand Reduction Threshold Price –** The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data (excluding Coordinated External Transactions) for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

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

(b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.

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

(d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} X - \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the month preceding the Demand Reduction Threshold Price's effective date.

(g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction Offer, or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer, a Demand Reduction Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) **Load Estimate** – The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) **Prorated Supply** – In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions are not used in determining the amount of energy (MW) in each marginal Supply Offer or Demand Reduction Offer to be cleared on a pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions.

(j) **Prorated Demand** – In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids, Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) **Virtuals** – All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

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

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers, Demand Reduction Offers, or Demand Bids in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as Generator Assets, DARDs or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume energy in the Real-Time dispatch unless the schedules for such Resources are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy supply or consumption, ancillary services, and related services, Start-Up Fees, No-Load Fees, Interruption Cost and the specified operating characteristics, offered by Market Participants.

(b) The ISO shall optimize the dispatch of energy and ancillary services from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Market consistent with the Supply Offers and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids, ancillary services offers and requirements, and the Forecast Energy Requirement Demand Quantity.

(c) Market Participants offering energy from facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled shall be governed by the following principles and procedures. The minimum duration of a Self-Schedule for a Generator Asset or DARD shall not result in the Generator Asset or DARD operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer. A DARD that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid. A Demand Response Resource shall not be Self-Scheduled.

III.1.10.4 External Resources.

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

III.1.10.5 Dispatchable Asset Related Demand.

(a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.

(b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:

(i) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand's ability to respond to Dispatch Instructions and the expected return date from the outage;

(ii) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;

(iii) abide by the ISO maintenance coordination procedures; and

(iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

III.1.10.6 Electric Storage

A storage facility is a facility that is capable of receiving electricity and storing the energy for later injection of electricity into the grid. A storage facility may participate in the New England Markets as described below.

(a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:

- (i) comprise one or more storage facilities at the same point of interconnection;
- (ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;
- (iii) be directly metered;
- (iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;
- (v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;
- (vi) settle its injection of electricity to the grid as a Generator Asset and any receipt of electricity from the grid as a DARD;
- (vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to, satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and
- (viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

(b) A storage facility that satisfies the requirements of this subsection (b) may participate in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:

- (i) satisfy the requirements applicable to an Electric Storage Facility; and
- (ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and
- (iii) be issued Dispatch Instructions in a manner that ensures the facility is not required to consume and inject simultaneously.

(c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility;

(ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;

(iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;

(iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;

(v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time, Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;

(vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;

(vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and

(viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).

(d) In clearing the Day-Ahead Energy Market, the ISO will respect Electric Storage Facility Initial State of Charge, Round Trip Efficiency, Maximum State of Charge, and Minimum State of Charge.

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

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

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

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

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

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

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

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

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

(g) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.

(h) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.

(i) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)

(j) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.

(k) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

III.1.10.7 External Transactions.

The provisions of this Section III.1.10.7 do not apply to Coordinated External Transactions.

(a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.

(b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, require a change in schedule.

(d) External Transactions submitted to the Real-Time Energy Market must contain the associated e-Tag ID and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) [Reserved.]

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone, as determined in accordance with Section III.12.4, that experienced price separation in the Annual Capacity Auction as determined in accordance with Section III.15.4.2.2(j) of Market Rule 1;

(2) The External Transaction is directly associated with an Export Offer Segment that did not receive a Capacity Supply Obligation in the Annual Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the unobligated Export Offer Segment;

(3) The External Node associated with the unobligated Export Offer Segment is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(ii) Annual Capacity Auction Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Offer Segment that did not receive a Capacity Supply Obligation in the Annual Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the unobligated Export Offer Segment;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Offer Segment is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward or Annual Capacity Auction in the direction of the export;

(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and Annual Capacity Auction Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the

ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and Annual Capacity Auction Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and Annual Capacity Auction Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.7.A Coordinated Transaction Scheduling.

The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15-minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated e-Tag ID at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, permit the transaction to be scheduled.

III.1.10.8 Scheduling Considerations.

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

In making the determination specified in this subsection (a), the ISO shall take into account, as applicable: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for ancillary services; (vi) the operational capabilities of any Resource to adjust the output, consumption, or demand reduction within the operating characteristics and parameters specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, or Demand Bid and any audited values of such operating characteristics and parameters; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination.

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

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

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

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

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

(b) Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead energy and ancillary services schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Market cannot be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors. The ISO shall use its best efforts to determine the least-cost means to satisfy any remaining reliability requirements of the New England Control Area for the Operating Day.

(d) Market Participants shall pay and be paid for the quantities of energy and ancillary services scheduled in the Day-Ahead Market based upon applicable Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Resources and to direct that schedules be changed to address an actual or potential Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) During the Re-Offer Period, Market Participants may submit revisions to the price of priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis or request to reduce the quantity of a priced External Transaction. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(b) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator

Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

(i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual-fuel Generator Assets), and the quantity and price pairs of its Blocks may be modified.

(ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.

(e) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit. A Market Participant may not request to Self-Schedule a Demand Response Resource. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.

(f) During the Operating Day, in the event that in a given hour a Market Participant seeks to modify a Supply Offer or Demand Bid after the deadline for modifications specified in Section III.1.10.9(c), then:

(i) the Market Participant may request that a Generator Asset be dispatched above its Economic Minimum Limit at a specified output. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Generator Asset will be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

(ii) the Market Participant may request that a Dispatchable Asset Related Demand be dispatched above its Minimum Consumption Limit at a specified value. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Dispatchable Asset Related Demand will be dispatched at or above the requested amount for the hour in question.

(g) During the Operating Day, in any interval in which a Generator Asset is providing Regulation, the upper limit of its energy dispatch range shall be reduced by the amount of Regulation Capacity, and the lower limit of its energy dispatch range shall be increased by the amount of Regulation Capacity. Any such adjustment shall not affect the Real-Time Reserve Designation.

(h) During the Operating Day, in any interval in which a Continuous Storage ATRR is providing Regulation, the upper limit of the associated Generator Asset's energy dispatch range shall be reduced by the Regulation High Limit, and the associated DARD's consumption dispatch range shall be reduced by the Regulation Low Limit. Any such adjustment shall not affect the Real-Time Reserve Designation.

(i) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output or Consumption and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control

Area; and (d) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Dispatchable Resources.

With the exception of Settlement Only Resources, Generator Assets that meet the size criteria to be Settlement Only Resources, External Transactions, and nuclear-powered Resources, all Resources must be Dispatchable Resources in the Energy Market and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.
2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources in the Energy Market are subject to the following requirements:

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Dispatchable Resources and the designation of Real-Time Operating Reserve to Dispatchable Resources, including the dispatchable portion of Resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources. Each Market Participant shall ensure that the entity controlling a Dispatchable Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.

(e) Settlement Only Resources are not eligible to be DNE Dispatchable Generators.

Wind, solar, and hydro Intermittent Power Resources that are not Settlement Only Resources are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:

(i) A Market Participant may elect, but is not required, to have a wind, solar, or hydro Intermittent Power Resource that is less than 5 MW and is connected through transmission facilities rated at less than 115 kV be dispatched as a DNE Dispatchable Generator.

(ii) A Market Participant with a hydro Intermittent Power Resource that is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range may elect to have that resource dispatched as a DDP Dispatchable Resource.

(f) The ISO may request that dual-fuel Generator Assets that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fuel Generator Assets that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fuel Generator Assets that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.

If the ISO anticipates or declares an Emergency Condition, all External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

III.1.11.5 Dispatchability Requirements for Intermittent Power Resources.

(a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.

(b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. Redeclarations must be updated throughout the Operating Day to reflect actual operating capabilities.

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

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

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

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

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

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

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

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

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

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

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

III.1.11.6 Non-Dispatchable Resources.

Non-Dispatchable Resources are subject to the following requirements:

(a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

APPENDIX A
MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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

III.A.1.1. Mission Statement.

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

III.A.1.2. Structure and Oversight.

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

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

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this ***Appendix A***.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this ***Appendix A***, the provisions of ***Appendix A*** shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III.A.17.3 are also part of the Participants Agreement and cannot be modified in either ***Appendix A*** or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

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

III.A.2. Functions of the Market Monitor.

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

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

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this ***Appendix A***). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

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

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

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

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

(a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this ***Appendix A***, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

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

(d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this ***Appendix A,*** provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

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

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

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

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

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

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

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

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

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

(d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this ***Appendix A.***

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

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

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

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

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

(i) *Economic withholding*, that is, submitting a Supply Offer or Day-Ahead Ancillary Services Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 or Section III.A.8 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.

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

(iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this ***Appendix A***.

(iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this ***Appendix A.***

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

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

(i) Anti-competitive gaming of Resources;

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

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

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

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

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

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this ***Appendix A***. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this ***Appendix A.*** If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

(l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.8, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

(m) Evaluate physical withholding of Supply Offers and Day-Ahead Ancillary Services Offers in accordance with Section III.A.4 below for referral to the Commission.

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

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

III.A.2.4.1. Purpose.

The mitigation measures set forth in this ***Appendix A*** for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule l (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this ***Appendix A***. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this ***Appendix A***, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential referral under Section III.A.19.

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

To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.8, III.A.10, III.A.11, III.A.21, III.A.22, and III.A.24 below.

III.A.2.4.3. Applicability.

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

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

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

III.A.2.4.5. Duration of Mitigation.

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

III.A.2.4.6. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied pursuant to Sections III.A.5 or III.A.8 due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the Operating Day associated with the Supply Offer or Day-Ahead Ancillary Services Offer to which such mitigation applied. The ISO shall correct the error as part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer or Day-Ahead Ancillary Services Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.2.4.7. Delay of Day-Ahead Market Due to Mitigation Process.

The posting of the Day-Ahead Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources and Benchmark Levels for Day-Ahead Ancillary Services Offers; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 and Day-Ahead Ancillary Services Benchmark Levels under Section III.A.8.2 for that Market Participant**.** In order for the Internal Market Monitor to revise Reference Levels or Day-Ahead Ancillary Services Benchmark Levels, or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 or Section III.A.8.1.1 for an Operating Day or hour for which the offer is submitted, all cost data and other verifiable supporting information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level or Day-Ahead Ancillary Services Benchmark Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

(a) If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(c), believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. If the Internal Market Monitor determines that there is an increased cost related to a Supply Offer, the Internal Market Monitor will either update the Reference Level or treat the offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted.

(b) If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(c), believes will cause the expected close-out costs or input costs associated with a Day-Ahead Ancillary Services Offer to exceed the level that would violate the conduct test specified in Section III.A.8.1.1 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. If the Internal Market Monitor determines that there is an increased cost related to a Day-Ahead Ancillary Services Offer, the Internal Market Monitor will either update one or both of the components of the Day-Ahead Ancillary Services Benchmark Level, as applicable, or treat the offer as not violating the conduct test specified in Section III.A.8.1.1 for the hour for which the offer is submitted.

(c) If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change.

(d) Any request pursuant to this Section III.A.3.1 must be submitted to the Internal Market Monitor with all supporting cost data and other verifiable supporting information. In order for a request pursuant to this Section III.A.3.1 to be considered for the purposes of the Day-Ahead Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Market. In order for a request to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. A request submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this ***Appendix A*** for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels and Day-Ahead Ancillary Services Benchmark Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels and both components of the Day-Ahead Ancillary Services Benchmark Levels applicable to that Market Participant's Supply Offers and any Day-Ahead Ancillary Services Offers through the MUI. Updated Reference Levels and components of the Day-Ahead Ancillary Services Benchmark Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels or the components of the Day-Ahead Ancillary Services Benchmark Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer and the Day-Ahead Ancillary Services Avoidable Input Cost for any associated Day-Ahead Ancillary Services Offers, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer and the Day-Ahead Ancillary Services Avoidable Input Cost for any associated Day-Ahead Ancillary Services Offers. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change, and for any associated Day-Ahead Ancillary Services Offers entered in the Day-Ahead Ancillary Services Market. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer and the Day-Ahead Ancillary Services Avoidable Input Cost for any associated Day-Ahead Ancillary Services Offers, the fuel price must be submitted prior to the applicable offer deadline.

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer and to cover an award consistent with any associated Day-Ahead Ancillary Services Offers, exclusive of resource-specific transportation costs. Modifications to Reference Levels or Day-Ahead Ancillary Services Avoidable Input Costs based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer and any Day-Ahead Ancillary Services Avoidable Input Cost or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer and any Day-Ahead Ancillary Services Avoidable Input Cost plus $2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer and any associated Day-Ahead Ancillary Services Offers, as of the time that the Supply Offer and any associated Day-Ahead Ancillary Services Offers were submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels and the components of Day-Ahead Ancillary Services Benchmark Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2
2 or more	6

III.A.4. Physical Withholding.

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

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

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

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

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

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

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

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

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

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

(c) As applied to the Day-Ahead Ancillary Services Market, withholding that exceeds the greater of 20% or 100 MW of the total Day-Ahead Ancillary Services capability of a Market Participant's Resources; or

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

III.A.4.2.2. Adjustment to Generating Capacity.

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

III.A.4.2.3. Withholding of Transmission.

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

III.A.4.2.4. Resources in Congestion Areas.

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

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Sections III.A.5 or III.A.8, as appropriate.

III.A.5. Supply Offer Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

(a) all Supply Offer parameters shall be reviewed for economic withholding;

(b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;

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

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

(a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;

(b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

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III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

(i) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;

(j) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than $25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated by substituting Supply Offers of Resources that have failed the applicable conduct test with the lesser of the Reference Level and Supply Offer. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

(a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using the lesser of their Reference Levels and Supply Offer for Resources that have failed the conduct test, or;

(b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using the lesser of their Reference Levels and Supply Offer for Resources that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Supply Offer Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or $100/MWh, whichever is lower. Offer block prices below $25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or $100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to the lesser of their Reference Levels and Supply Offer, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or $25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or $25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to the lesser of their Reference Levels and Supply Offer, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to the lesser their of Reference Levels and Supply Offer, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then the financial parameters of its Supply Offer are set the lesser of to their Reference Levels and Supply Offer, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then the financial parameters of its Supply Offer are set to the lesser of their Reference Levels and Supply Offer, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

i. local first contingency;
ii. local second contingency;
iii. VAR or voltage;
iv. distribution (Special Constraint Resource Service);

v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to the lesser of their Reference Levels and Supply Offer. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then the financial parameters of its Supply Offer are set to the lesser of their Reference Level or Supply Offer, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then the financial parameters of its Supply Offer shall be set to the lesser of their Reference Levels and Supply Offer, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

(a) If the Resource is starting from an offline state, the Start-Up Fee;
(b) The sum of the No Load Fees for the Commitment Period; and
(c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 "General Threshold Energy Mitigation" or III.A.5.5.2 "Constrained Area Energy Mitigation" is in effect for the following duration:

(a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:

i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,

ii. for constrained area energy mitigation, the Resource is not located within a constrained area.

(b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 "Constrained Area Energy Mitigation"), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 "Manual Dispatch Energy Mitigation" is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource's Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 "General Threshold Commitment Mitigation", III.A.5.5.5 "Constrained Area Commitment Mitigation", or III.A.5.5.6 "Reliability Commitment Mitigation" is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 "Start-Up Fee and No-Load Fee Mitigation" is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

Market Participants are responsible for providing the Internal Market Monitor with all the information and data necessary for the Internal Market Monitor to calculate up-to-date Reference Levels for each of a Market Participant's Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

(a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.

(b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.
(c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, Interruption Costs and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of an offer according to the following hierarchy, under which the first method that can be calculated is used:

(a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
(b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
(c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

(a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.
(b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
(c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
(d) For any Operating Day for which, during the previous 90 days:
 (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
 (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of

economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.

(e) When in any hour the incremental energy parameter of an offer, including adjusted offers pursuant to Section III.2.4, is greater than $1,000/MWh.

For the purposes of this subsection:

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

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

iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.

iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.

(e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.

(f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:

(i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,

(ii) No-Load Fee or its corresponding fuel blends,

(iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,

(iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and

(v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

(a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".

(b) Costs must be documented.

(c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible. All cost estimates, including opportunity cost estimates, must be quantified and analytically supported.

(d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.

(e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

   i. Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and

   ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy/Reduction:
(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

(a) emissions limits;
(b) water storage limits;
(c) other operating permits that limit production of energy; and
(d) reducing electricity consumption.

No-Load:
(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price)

+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up/Interruption:
(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. Day-Ahead Ancillary Services Offer Mitigation.

Day-Ahead Ancillary Services Offers will be evaluated for economic withholding in the Day-Ahead Market and mitigated as described in this Section III.A.8.

III.A.8.1. Conduct and Impact Test.

III.A.8.1.1. Conduct Test.

A Day-Ahead Ancillary Services Offer price fails the conduct test for Day-Ahead Ancillary Services Offer mitigation in a given hour if such price exceeds an amount greater than the sum of (i) the greater of $2/MWh and 200% of the Day-Ahead Ancillary Services Expected Close-Out Component as described in Section III.A.8.2.1; and (ii) 150% of the Day-Ahead Ancillary Services Avoidable Input Cost as described in Section III.A.8.2.2.

III.A.8.1.2. Impact Test.

A Day-Ahead Ancillary Services Offer with a price that fails the conduct test for Day-Ahead Ancillary Services Offer mitigation shall be evaluated against the impact test for Day-Ahead Ancillary Services Offer mitigation. A Day-Ahead Ancillary Services Offer fails the impact test for Day-Ahead Ancillary Services Offer mitigation if there is an increase in any Day-Ahead Price, as calculated pursuant to Sections III.A.8.3 or III.A.8.4, in any hour of the Operating Day and such increase is higher than the greater of (a) $3/MWh and (b) 150% of the median difference between:

(i) the threshold prices for failing the conduct test described in Section III.A.8.1.1 for all Day-Ahead Ancillary Services Offers in the hour of the Operating Day being evaluated; and

(ii) the Day-Ahead Ancillary Services Benchmark Levels as described in Section III.A.8.2 for all Day-Ahead Ancillary Services Offers in the hour of the Operating Day being evaluated.

III.A.8.1.3. Consequence of Failing Both Conduct and Impact Test.

If any Day-Ahead Ancillary Services Offer with a price that fails the Day-Ahead Ancillary Services Offer conduct test fails the impact test, then all Day-Ahead Ancillary Services Offer prices that failed the conduct test in the hour being evaluated shall be set to the applicable Day-Ahead Ancillary Services Benchmark Level.

III.A.8.2. Day-Ahead Ancillary Services Benchmark Levels.

A resource's Day-Ahead Ancillary Services Benchmark Level for the hour associated with the resource's Day-Ahead Ancillary Services Offer is the sum of the Day-Ahead Ancillary Services Expected Close-Out Component and the resource's Day-Ahead Ancillary Services Avoidable Input Cost for such hour.

III.A.8.2.1. Day-Ahead Ancillary Services Expected Close-Out Component.

The Day-Ahead Ancillary Services Expected Close-Out Component for a given hour is the lesser of the following:

(a) the expected value of the greater of (i) the hourly Real-Time Hub Price less the hourly Day-Ahead Ancillary Services Strike Price and (ii) zero; and

(b) the historical average of the estimated likelihood that the Real-Time Hub Price will be equal to or less than its expected value, multiplied by the greater of $100/MWh and the expected hourly Real-Time Hub Price.

III.A.8.2.2. Day-Ahead Ancillary Services Avoidable Input Cost.

For purposes of calculating Day-Ahead Ancillary Services Benchmark Levels and conducting the conduct test described in Section III.A.8.1.1, Day-Ahead Ancillary Services Avoidable Input Costs shall be determined as follows:

(a) For a Generator Asset with natural gas as its only fuel type, or a dual-fuel Generator Asset that has specified natural gas as its fuel type in its Supply Offer for the hour associated with the Day-Ahead Ancillary Services Offer, the Day-Ahead Ancillary Services Avoidable Input Cost shall be calculated based on the asset's average heat rate and the expected price of natural gas to cover the Day-Ahead Ancillary Services award, adjusted for the expected hourly Real-Time Hub Price.

(b) For an asset that is an Electric Storage Facility, the Day-Ahead Ancillary Services Avoidable Input Cost shall be calculated based on the expected cost of charging energy to cover the Day-Ahead Ancillary Services award, adjusted for the expected Real-Time revenue associated with that charged energy during the Operating Day.

(c) For asset types other than those described in subsections (a) and (b), the Day-Ahead Ancillary Services Avoidable Input Cost shall be zero.

(d) The Day-Ahead Ancillary Services Avoidable Input Cost shall in no case be less than zero.

III.A.8.2.3. Cost Information Provided Through Consultation.

In performing the Day-Ahead Ancillary Services Benchmark Level calculations in this Section III.A.8.2, the Internal Market Monitor shall take into account, as appropriate, information provided by the Market Participant through the consultation process described in Section III.A.3. The criteria enumerated in (a) through (e) of Section III.A.7.5 shall apply to estimates of costs when performing Day-Ahead Ancillary Services Benchmark Level calculations.

III.A.8.3. Calculation of Impact to the Day-Ahead Ancillary Services Market.

For the purpose of determining any increase in Day-Ahead Ancillary Services prices pursuant to Section III.A.8.1.2, the Day-Ahead Ancillary Service impact test shall calculate the difference between two Day-Ahead Ancillary Service prices for each product in each hour. The first price shall be calculated based on a run of the Day-Ahead Market using all Day-Ahead offers and bids as submitted. The second price shall be calculated based on a second run of the Day-Ahead Market substituting Day-Ahead Ancillary Services Benchmark Levels for the Day-Ahead Ancillary Services Offer prices that have failed the Day-Ahead Ancillary Services conduct test.

III.A.8.4. Calculation of Impact to the Day-Ahead Energy Market.

For the purpose of determining any increase in Day-Ahead energy prices pursuant to Section III.A.8.1.2, the Day-Ahead Ancillary Service impact test shall calculate the difference between two prices in each hour. The first price shall be the Hub Price calculated based on a run of the Day-Ahead Market using all Day-Ahead offers and bids as submitted. The second price shall be the Hub Price calculated based on a second run of the Day-Ahead Market substituting Day-Ahead Ancillary Services Benchmark Levels for the Day-Ahead Ancillary Services Offer prices that have failed the Day-Ahead Ancillary Services conduct test.

III.A.8.5. Duration of Day-Ahead Ancillary Services Offer Mitigation.

Any mitigation imposed on a Day-Ahead Ancillary Services Offer pursuant to this Section III.A.8 is in effect only for the hour in which the Day-Ahead Ancillary Services Offer has a price that fails the conduct test in Section III.A.8.1.1.

III.A.9. Regulation.

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

III.A.10. Demand Bids.

The Internal Market Monitor will monitor the Energy Market as outlined below:

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

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

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

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

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

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

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

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

III.A.11.3. Mitigation Measures.

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

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

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

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

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

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

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

III.A.12. Cap on FTR Revenues.

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

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Capacity Market.

In accordance with the following provisions of this ***Appendix A***, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Capacity Market and the exit of certain resources, in the form of deactivations, from the Capacity Market. Sections III.A.21, III.A.22, III.A.23, and III.A.24 of this ***Appendix A*** specify the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Capacity Market.

Sections III.13.4 and III.15.5 of Market Rule 1 address reconfiguration auctions in the Capacity Market. As addressed in Sections III.13.4.2 and III.15.5.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility and Resource Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities and is supplemented by Operating Procedure No. 5, which addresses outage scheduling for transmission facilities and Resources. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners and Resource Lead Market Participants. The Internal Market Monitor shall have the right to request that each Transmission Owner or Resource Lead Market Participant provide information to the Internal Market Monitor concerning the Transmission Owner or Resource Lead Market Participant's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner or Resource Lead Market Participant shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this ***Appendix A***. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.

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

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Cost Recovery Request Following Capping.

If as a result of an offer being capped under Section III.1.9, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was capped, the Market Participant may, within 20 days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit an additional cost recovery request to the Internal Market Monitor.

A request under this Section III.A.15 may seek recovery of additional costs incurred for the duration of the period of time for which the Resource was operated at the cap.

III.A.15.1.1. Timing and Contents of Request.

Within 20 days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant requesting additional cost recovery under this Section III.A.15.1 shall submit to the Internal Market Monitor a request in writing detailing: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data, documentation and calculations for those costs; and (ii) an explanation of why the actual costs of operating the Resource exceeded the capped costs.

III.A.15.1.2. Review by Internal Market Monitor.

To evaluate a Market Participant's request, the Internal Market Monitor shall use the data, calculations and explanations provided by the Market Participant to verify the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, using the same standards and methodologies the Internal Market Monitor uses to evaluate requests to update Reference Levels under Section III.A.3 of Appendix A. To the extent the Market Participant's request warrants additional cost recovery, the Internal Market Monitor shall reflect that adjustment in the Resource's Reference Levels for the period covered by the request. The ISO shall then re-apply the cost verification and capping formulas in Section III.1.9 using the updated Reference Levels to re-calculate the adjustments to the Market

Participant's offers required thereunder, and then shall calculate additional cost recovery using the adjusted offer values.

Within 20 days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the Market Participant's request, detailing (i) the extent to which it agrees with the request with supporting explanation, and (ii) a calculation of the additional cost recovery. Changes to credits and charges resulting from an additional cost recovery request shall be included in the Data Reconciliation Process.

III.A.15.1.3. Cost Allocation.

The ISO shall allocate charges to Market Participants for payment of any additional cost recovery granted under this Section III.A.15.1 in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.15.2. Section 205 Filing Right.

(i) If either

(a) as a result of mitigation applied to a Resource under this ***Appendix A*** for all or part of one or more Operating Days, or

(b) in the absence of mitigation, as a result of a request under Section III.A.15.1 being denied in whole or in part,

a Market Participant believes that it will not recover the fuel, variable operating and maintenance costs, or Day-Ahead Ancillary Services close-out or input costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was mitigated or the Section III.A.15.1 request was denied, the Market Participant may submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. For filings to address cost recovery under Section III.A.15.2(i)(a), the filing must be made within sixty days of receipt of the first Invoice issued containing credits or charges for the applicable Operating Day. For filings to address cost recovery under Section III.A.15.2(i)(b), the filing must be made within sixty days of receipt of the first Invoice issued that reflects the denied request for additional cost recovery under Section III.A.15.1.

(ii) A request under this Section III.A.15.2 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having a Section III.A.15.1 request denied, costs incurred for the duration of the period of time addressed in the Section III.A.15.1 request.

(iii) A Market Participant also may submit a filing under Section III.A.15.2(i)(a) to seek recovery of opportunity costs within the Day-Ahead Market as a result of mitigation applied to the Resource's Day-Ahead Ancillary Services Offer under Section III.A.8. To recover such opportunity costs, the Market Participant must demonstrate as part of the filing requirements of Section III.A.15.2.1(iii) and (iv) that the original, unmitigated Day-Ahead Ancillary Services Offer reflected costs anticipated by the Market Participant at the time the offer was made. The filing must be made within the time period specified for a filing to address cost recovery under Section III.A.15.2(i)(a).

III.A.15.2.1. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel, variable operating and maintenance costs, or Day-Ahead Ancillary Services close-out or input costs, or opportunity costs as described in Section III.A.15.2(iii), for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) regarding actual costs, an explanation of (a) why such actual costs exceeded the Reference Level or Day-Ahead Ancillary Services Benchmark Level costs or, (b) in the absence of mitigation, why such actual costs, as reflected in the original offer and to the extent not recovered under Section III.A.15.1, exceeded the costs as reflected in the capped offer; (iii) sufficient documentation and information supporting the basis for the original offer at the time the offer was submitted; (iv) an explanation as to why the original offer should not have been mitigated to the applicable Reference Level or Benchmark Level, or in the absence of mitigation, why the Section III.A.15.1 request should not have been denied in whole or in part; (v) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.2.2; and (vi) all requested regulatory costs in connection with the filing.

III.A.15.2.2. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the applicable Invoice, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15.2 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2.1(i), (ii), (iii), and (iv) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15.2 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.2.

III.A.15.2.3. Cost Allocation.

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

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

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

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

III.A.16.2. Standard of Review.

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

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

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

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

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

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

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

III.A.17.2.2. Quarterly Report.

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

III.A.17.2.3. Reporting on General Performance of the Capacity Market.

The performance of the Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. The Internal Market Monitor shall report on the functioning of the Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this ***Appendix A***.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

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

III.A.17.2.5. Additional Ad Hoc Reporting on Performance and Competitiveness of Markets.

In furtherance of its function under Section III.A.2 of this ***Appendix A***, including without limitation Sections III.A.2.3(e) and (k) therein, the Internal Market Monitor shall perform independent evaluations and prepare ad hoc reports on the overall competitiveness and performance of the New England Markets or particular aspects of the New England Markets, including the competitiveness and performance of a major market design change. The Internal Market Monitor shall have the sole discretion to determine when to prepare an ad hoc report and may prepare such report on its own initiative or pursuant to a request by the ISO, New England state public utility commissions or one or more Market Participants. However, the Internal Market Monitor will report on the competitiveness and performance of any new major market design change within one to three years, respectively, of the effective date of operation of the market design change, or as soon as adequate data becomes available. While the Internal Market Monitor may solicit or receive input of the External Market Monitor, Market Participants and other stakeholders, including New England state public utility commissions, the methodology and criteria used to conduct its independent analysis shall be at the sole discretion of the Internal Market Monitor. The Internal Market Monitor shall describe its methodology and criteria used in an ad hoc report of its significant findings and, if any, recommendations. The Internal Market Monitor shall file with the Commission and post to the ISO's website a final version of an ad hoc report. Thereafter, the Internal Market Monitor shall continue to report on the competitiveness and performance of any market design change that has been the subject of an ad hoc report in its quarterly or annual reports under Sections III.A.17.2.2 and III.A.17.2.4.

III.A.17.3. Periodic Reporting by the External Market Monitor.

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

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

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

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

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

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

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

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

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

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

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

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

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

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

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

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

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct, as amended from time to time and available on the ISO's website. Consistent with the ISO New England Inc. Code of Conduct, at a minimum each such monitoring unit and its employees: (a) must have no material affiliation with any Market Participant or Affiliate, (b) must have no material financial interest in any Market Participant or Affiliate with potential exceptions for mutual funds and non-directed investments, (c) must not engage in any market transactions other than the performance of their duties hereunder, (d) may not accept anything of value from a Market Participant in excess of a *de minimis* amount, and (e) must advise a supervisor in the event they seek employment with a Market Participant, and must disqualify themselves from participating in any matter that would have an effect on the financial interest of the Market Participant.

III.A.18.2. Additional Ethical Conduct Standards.

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

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

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

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of ***Appendix A***, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

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

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

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

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

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

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

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

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

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

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

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

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

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

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

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

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

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

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

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

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

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

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

III.A.21. Buyer-Side Market Power Review for the Capacity Market.

(a) Any capacity that has not been previously offered into an Annual Capacity Auction and that will be included in a Capacity Offer once it satisfies the necessary auction qualification requirements in Sections III.15.2 and III.15.3 of Market Rule 1 is subject to the provisions of this Section III.A.21. The Internal Market Monitor shall conduct a buyer-side market power review and determine a resource-specific Capacity Offer Floor Price for such capacity unless such capacity is exempted as described in this Section III.A.21. Capacity for which the Internal Market Monitor determines a Capacity Offer Floor Price pursuant to this Section III.A.21 remains subject to the provisions of this Section III.A.21 until the capacity is awarded a Capacity Supply Obligation through an Annual Capacity Auction.

(b) For the purposes of this Section III.A.21, capacity not previously offered into an Annual Capacity Auction includes the following:

(i) capacity supplied from a resource that has never been offered into an Annual Capacity Auction;

(ii) capacity supplied from a resource previously offered into an Annual Capacity Auction, where such capacity represents an increase in the resource's total capacity as compared to the highest Capacity Supply Obligation (measured in MW) awarded to the resource in a prior

Annual Capacity Auction or Forward Capacity Auction, and the increase is associated with a material change in the resource as defined in Section III.15.2.4.1(b); and

(iii) capacity supplied from a previously deactivated or retired resource, or portion thereof, that seeks to re-enter the Capacity Market pursuant to Section III.15.2.4 and that has not been offered into an Annual Capacity Auction since deactivation or retirement.

(c) For the purposes of this Section III.A.21, capacity not previously offered into an Annual Capacity Auction does not include the following:

(i) capacity supplied from an Import Capacity Resource that is (1) backed by a multi-year contract and (2) previously offered into an Annual Capacity Auction or Forward Capacity Auction while backed by that contract; or

(ii) for the purpose of the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, capacity for which a Capacity Supply Obligation had been awarded in a Forward Capacity Auction and not subsequently de-listed pursuant to a Permanent De-List Bid or a Retirement De-List Bid.

(d) A Lead Market Participant must be designated for a resource that will supply the capacity that is subject to the provisions of this Section III.A.21, notwithstanding the development or commercialization status of the resource.

III.A.21.1. Applicability of Buyer-Side Market Power Review.

Review submission requirements for capacity subject to the Internal Market Monitor's buyer-side market power review and exemptions from the Internal Market Monitor's buyer-side market power review are described in this Section III.A.21.1.

III.A.21.1.1. Capacity Not Exceeding 5 MW.

Capacity not previously offered into an Annual Capacity Auction that will be included in a Capacity Offer is not subject to the Internal Market Monitor's buyer-side market power review or a Capacity Offer Floor Price if the amount of the capacity does not exceed an Annual Qualified Capacity of 5 MW.

III.A.21.1.2. Passive Demand Response Resources.

Capacity not previously offered into an Annual Capacity Auction that will be included in a Capacity Offer and that is supplied from an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource is not subject to the Internal Market Monitor's buyer-side market power review or a Capacity Offer Floor Price.

III.A.21.1.3 Import Capacity Not Associated with Transmission Investments.

Import capacity not previously offered into an Annual Capacity Auction that will be included in a Capacity Offer is not subject to the Internal Market Monitor's buyer-side market power review or a Capacity Offer Floor Price, unless the import capacity is either:

(i) supplied from a single new External Resource, and the External Resource or import capacity supplied by the External Resource is controlled by or receiving out-of-market revenues (as defined in Section III.A.21.3(a)(ii)) from an entity or individual that (a) made or is making an investment in transmission that increases New England's import capability or (b) has a contractual arrangement with such an entity or individual, or

(ii) is controlled by or receiving out-of-market revenues (as defined in Section III.A.21.3(a)(ii)) from an Elective Transmission Upgrade Interconnection Customer as defined in Section II.47.5, Affiliate of an Elective Transmission Upgrade Interconnection Customer, or sponsor of an Elective Transmission Upgrade.

For the purposes of this Section III.A.21.1.3, the term "controlled" has the meaning set forth in Section III.A.23.4.

III.A.21.1.4. Capacity Supported by a Qualifying Load-Side Relationship Certification.

Capacity not previously offered in an Annual Capacity Auction that will be included in a Capacity Offer will not be subject to the Internal Market Monitor's buyer-side market power review or a Capacity Offer Floor Price if the Lead Market Participant for the resource supplying the capacity complies with the submission requirements described in Section III.A.21.1.5 and submits a Load-Side Relationship Certification demonstrating one of the following qualifying circumstances:

(a) the Lead Market Participant and its Affiliates or partners, if any, are not load serving entities and are neither receiving nor expecting to receive any revenues from a load serving entity, state, or political subdivision of a state that relate to the development, operation, control, or output of the resource supplying the capacity (excepting any revenues earned through an ISO-administered market); or

(b) the resource supplying the capacity is a Sponsored Policy Resource.

For the purpose of this Section III.A.21, a load serving entity is any entity that has or is the type of entity that could acquire a Capacity Load Obligation in the Capacity Market.

To demonstrate such circumstances, the Lead Market Participant must include as part of the Load-Side Relationship Certification a sworn affidavit from an officer or principal for the Lead Market Participant that includes factual detail sufficient to explain the qualifying circumstances. The Lead Market Participant must submit the Load-Side Relationship Certification to the ISO concurrent with the submission of information made pursuant to Section III.A.21.1.5. If the ISO is unable to determine from the Load-Side Relationship Certification that one of the qualifying circumstances exists, the capacity shall be subject to buyer-side market power review pursuant to Section III.A.21.2.

III.A.21.1.5. Submission of Information for Exemption or Internal Market Monitor Review.

(a) The Lead Market Participant for a resource supplying capacity not previously offered into an Annual Capacity Auction that will be included in a Capacity Offer must submit to the ISO the following, unless the capacity meets the exemption requirements of Section III.A.21.1.1, Section III.A.21.1.2, or Section III.A.21.1.3:

(i) the qualification data described and referenced in Section III.15.2.1.1(a);

(ii) the name of any Affiliates of the Lead Market Participant that are load serving entities;

(iii) for capacity supplied from a resource previously offered into an Annual Capacity Auction as described in Section III.A.21(b)(ii), information identifying any changes to the resource's design or operating characteristics and the impact of such changes on the resource's total capacity;

(iv) for capacity that satisfies either of the qualifying circumstances set forth in Section III.A.21.1.4, a Load-Side Relationship Certification as described in Section III.A.21.1.4;

(v) for capacity that does not satisfy either of the qualifying circumstances set forth in Section III.A.21.1.4, the lowest price at which the Lead Market Participant requests to offer the capacity in the Annual Capacity Auction and sufficient documentation and information for a buyer-side market power review pursuant to Section III.A.21.2. Such documentation and information must include all financial estimates, projected revenues, and cost projections for the resource supplying the capacity, including the resource's pro-forma financing support data and anticipated out-of-market revenues (as defined in Section III.A.21.3(a)(ii)). For capacity that has achieved commercial operation prior to the submission of this information, such documentation must also include all financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation.

(b) With the exception of capacity that will be offered into the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028 or the Capacity Commitment Period beginning on June 1, 2029, the Lead Market Participant may submit the information required by subsection (a) as early as the first Business Day of January of the third calendar year prior to the first Annual Capacity Auction for which the capacity may be eligible to be offered, as determined with reference to the capacity's proposed commercial operation date. For capacity that will be offered into the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028 or the Capacity Commitment Period beginning on June 1, 2029, the earliest submission date will be the first Business Day of June 2026.

(c) If not already submitted pursuant to subsection (b), the Lead Market Participant must submit the information required by subsection (a) no later than the first Business Day of June of the calendar year prior to the first Annual Capacity Auction into which the capacity will be offered pursuant to Section III.A.22.1.

(d) By the end of the fifth calendar month following the month during which the submission of information pursuant to subsection (a) was made, the ISO shall notify the Lead Market Participant of any ISO determination as to whether the capacity is exempt from buyer-side market power review pursuant to Section III.A.21.1.4 and the basis for such determination, any Capacity Offer Floor Price for the capacity, and any Internal Market Monitor determinations regarding whether a requested lowest offer price submitted pursuant to subsection (a) must be mitigated, as described in Section III.A.21.2.3. The ISO and the Internal Market Monitor shall not disclose to the Lead Market Participant any information or analysis regarding the potential impact on Capacity Clearing Prices of any offer of the capacity into the Annual Capacity Auction.

(e) A Lead Market Participant that submits a Load-Side Relationship Certification must be prepared to provide both (1) the lowest price at which the Lead Market Participant requests to offer the capacity in the Annual Capacity Auction and (2) the documentation and information described in subsection (a)(v), in the event that the ISO determines that the Load-Side Relationship Certification does not meet the requirements of Section III.A.21.1.4. If the ISO rejects a Load-Side Relationship Certification, the Lead Market Participant must promptly provide this information, and the capacity shall be subject to buyer-side market power review pursuant to Section III.A.21.2.

(f) A Lead Market Participant that submits a Load-Side Relationship Certification is under a continuing obligation through the time of the Annual Capacity Auction to withdraw the Load-Side Relationship Certification if, at any point through the time of the Annual Capacity Auction, the capacity ceases to satisfy the qualifying circumstances set forth in Section III.A.21.1.4 that provided the basis of the Load-Side Relationship Certification. If at the time of withdrawal, the Lead Market Participant submits a substitute Load-Side Relationship Certification demonstrating alternate qualifying circumstances that the ISO determines meets the requirements of Section III.A.21.1.4, then the capacity will continue to be exempt from the Internal Market Monitor's buyer-side market power review pursuant to Section III.A.21.1.4. If no substitute Load-Side Relationship Certification is submitted at the time of withdrawal and the capacity is not exempt from buyer-side market power review pursuant to Section III.A.21.1.1, Section III.A.21.1.2, or Section III.A.21.1.3, then the following shall apply:

(i) If the withdrawal occurs no later than the first Business Day of June of the calendar year prior to the Annual Capacity Auction, the Lead Market Participant must submit concurrently with the withdrawal both (1) the lowest price at which the Lead Market Participant requests to offer the capacity in the Annual Capacity Auction and (2) the documentation and information described in subsection (a)(v). The capacity shall then be subject to buyer-side market power review pursuant to Section III.A.21.2, unless a Capacity Offer Floor Price already has been calculated for the capacity subject to review. If a Capacity Offer Floor Price already has been calculated, no additional review is required.

(ii) If the withdrawal occurs later than the first Business Day of June of the calendar year prior to the Annual Capacity Auction, the capacity shall be treated as though no submission of information was made pursuant to Section III.A.21.1.5 and be assigned a Capacity Offer Floor Price as described in Section III.A.21.3(g).

(g) A Lead Market Participant that submitted a requested lowest offer price pursuant to subsection (a) is under a continuing obligation through the time of the Annual Capacity Auction to submit a Load-Side Relationship Certification if, at any point through the time of the Annual Capacity Auction, circumstances change such that either of the qualifying circumstances set forth in Section III.A.21.1.4 can be demonstrated for the capacity associated with the requested lowest offer price. If the Load-Side Relationship Certification is submitted no less than 21 days prior to the Annual Capacity Auction Offer Window and the ISO determines that the Load-Side Relationship Certification meets the requirements of Section III.A.21.1.4, then the capacity will not be subject to a Capacity Offer Floor Price, notwithstanding the results of any previously conducted buyer-side market power review.

(h) If a Lead Market Participant fails to provide a submission pursuant to subsection (a) as required pursuant to this Section III.A.21.1.5, the capacity that would be the subject of the submission will be assigned a Capacity Offer Floor Price as described in Section III.A.21.3(g).

III.A.21.2. Review for the Exercise of Buyer-Side Market Power.

The Internal Market Monitor shall review requested lowest offer prices submitted pursuant to Section III.A.21.1.5 for the potential exercise of buyer-side market power following the process described in this Section III.A.21.2 and will determine a Capacity Offer Floor Price for the capacity that is the subject of the submission.

III.A.21.2.1. Conduct Test.

The Internal Market Monitor will perform a conduct test by reviewing the information submitted pursuant to Section III. A.21.1.5 and determining a break-even price, as described in Section III.A.21.3, for the capacity subject to review. A requested lowest offer price for capacity subject to review fails the conduct test if the Internal Market Monitor determines a break-even price that exceeds the requested lowest offer price.

III.A.21.2.2. Demonstration of Lack of Incentive to Exercise Buyer-Side Market Power.

If the Lead Market Participant fails to demonstrate either of the qualifying circumstances set forth in Section III.A.21.1.4 to the ISO through a Load-Side Relationship Certification because the Lead Market Participant is or is affiliated with a load serving entity or because the Lead Market Participant receives or expects to receive revenues outside of ISO-administered markets from a load serving entity, the Lead Market Participant is entitled to submit documentation and information as part of the submission of information pursuant to Section III.A.21.1.5 to demonstrate that, notwithstanding such a relationship with a load serving entity with regard to the resource supplying the capacity subject to review, such load serving entity would be unlikely to realize a material, net financial benefit from any reduction in Annual Capacity Auction clearing prices resulting from entry of the capacity in the Annual Capacity Market. If, after consideration of such documentation and information, the Internal Market Monitor determines that a load serving entity as described in this Section III.A.21.2.2 would be unlikely to realize such a material, net financial benefit, then the Internal Market Monitor will not subject the requested lowest offer price to the mitigation described in Section III.A.21.2.3. For the avoidance of doubt, a Lead Market Participant may not utilize the provisions of this Section III.A.21.2.2 if it receives or expects to receive any revenues from a state, or from a political subdivision of a state that is not also a load serving entity, that relate to the development, operation, control, or output of the resource supplying the capacity.

As part of the documentation and information the Lead Market Participant submits pursuant to this Section III.A.21.2.2, the Lead Market Participant must include in its documentation and information a disclosure of any and all direct or indirect relationships or arrangements with a load serving entity regarding the resource supplying the capacity and any other information necessary for the Internal Market Monitor to make the determination described in this Section III.A.21.2.2.

III.A.21.2.3. Consequence of Failing the Conduct Test and Failing to Rebut Presumed Incentive.

If a requested lowest offer price for capacity subject to review fails the conduct test and the Internal Market Monitor does not determine the lack of a material, net financial benefit to a load serving entity, as described in Section III.A.21.2.2, the Internal Market Monitor-determined break-even price calculated as part of the conduct test shall be the Capacity Offer Floor Price, as described in Section III. A.21.3(d).

III.A.21.3. Capacity Offer Floor Prices.

For capacity not previously offered into an Annual Capacity Auction for which the Internal Market Monitor is required to determine a Capacity Offer Floor Price, the Internal Market Monitor shall use the methodology described in this Section III.A.21.3 to make such a determination.

(a) When determining a Capacity Offer Floor Price for any capacity not previously offered into an Annual Capacity Auction, the Internal Market Monitor shall determine a break-even price for the capacity by entering all relevant resource capital and operating costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into a capital budgeting model and calculating the break-even contribution required from the Annual Capacity Market to yield a discounted cash flow with a net present value of zero for the project.

(i) The default model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties). The model horizon shall be longer or shorter than 20 years for a resource's break-even contribution calculation, if sufficiently documented in the offer information submitted pursuant to Section III. A.21.1.5. Adjustments to the model and calculation methodology will be made for capacity supplied from certain types of Demand Capacity Resources and Distributed Energy Capacity Resources as follows:

(1) For Demand Response Assets or Distributed Energy Resources with demand reduction capability, the Internal Market Monitor will model discounted cash flows over the contract life.

(2) For Demand Response Assets or Distributed Energy Resources with demand reduction capability that are large commercial or industrial customers that use pre-existing equipment or strategies, the Internal Market Monitor will include new equipment costs and annual operating costs, such as customer incentives and sales representative commissions, as incremental costs.

(3) For Demand Response Assets or Distributed Energy Resources with demand reduction capability that are residential or small commercial customers that do not use pre-existing equipment or strategies, the Internal Market Monitor will include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs as incremental costs.

(ii) In calculating the break-even contribution for the capacity, the Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used for such calculation. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Annual Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Lead Market Participant shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(iii) For capacity supplied from a Demand Capacity Resource or Distributed Energy Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource or Distributed Energy Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response

Resource or Distributed Energy Resource Aggregation, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iv) For capacity not previously offered into an Annual Capacity Auction that has achieved commercial operation prior to the submission of information pursuant to Section III.A.21.1.5, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such capacity, the prevailing market conditions will be those that were in place at the time of the decision to construct or change the design or operating characteristics of the resource supplying the capacity.

(b) Sufficient documentation and information must be included in the submission of information pursuant to Section III.A.21.1.5 to allow the Internal Market Monitor to make the determinations described in this Section III.A.21.3. If the supporting documentation and information is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Lead Market Participant to gather further information as necessary to complete its analysis. If after consultation, the Lead Market Participant does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the capacity subject to review shall be treated as though no submission of information was made pursuant to Section III.A.21.1.5 and be assigned a Capacity Offer Floor Price as described in Section III.A.21.3(g).

(c) If the Internal Market Monitor determines that the requested offer price is equal to or greater than the Internal Market Monitor-determined break-even price, then the Capacity Offer Floor Price shall be equal to the requested offer price.

(d) If the Internal Market Monitor determines that the requested offer price is less than the Internal Market Monitor-determined break-even price and the Internal Market Monitor does not determine the lack of a material, net financial benefit to a load serving entity, as described in Section III.A.21.2.2, then the Capacity Offer Floor Price shall be equal to the Internal Market Monitor-determined break-even price.

(e) After the Seasonal Qualified Capacity Values are determined for the resource supplying the capacity subject to the Capacity Offer Floor Price, the Internal Market Monitor may recalculate the break-even price as necessary to update a Capacity Offer Floor Price such that it reflects the Seasonal Qualified

Capacity Values. During this recalculation, the Internal Market Monitor shall change only inputs and assumptions used in the initial determination of the break-even price that depend on resource capacity values. The Internal Market Monitor shall notify the Lead Market Participant of any update to the Capacity Offer Floor Price concurrently with the Seasonal Qualified Capacity Notification Deadline. The Internal Market Monitor may further update the Capacity Offer Floor Price as necessary to reflect changes in a resource's Seasonal Qualified Capacity Values that occur after the Seasonal Qualified Capacity Notification Date and shall notify the Lead Market Participant of any such further update on the same date as any notifications made by the ISO pursuant to Section III.15.2.7(d).

(f) In accordance with Section III.15.4.2.2(c), capacity having a Capacity Offer Floor Price determined pursuant to this Section III.A.21.3 that is higher than the Capacity Auction Offer Price Cap shall not be taken into account in the clearing of the Annual Capacity Auction.

(g) If a Lead Market Participant fails to provide a submission of information by the deadline set forth in Section III.A.21.1.5(c) and the capacity is not exempt from buyer-side market power review pursuant to Sections III.A.21.1.1, III.A.21.1.2, or III.A.21.1.3, the capacity will be subject to a Capacity Offer Floor Price in each Annual Capacity Auction into which the capacity is being offered that equals the Capacity Auction Offer Price Cap calculated for such Annual Capacity Auction, unless a Capacity Offer Floor Price is calculated pursuant to subsection (h)(i) of this Section III.A.21.3.

(h) Capacity for which a Capacity Offer Floor Price has been determined pursuant to this Section III.A.21.3 will remain subject to that Capacity Offer Floor Price until the capacity clears and is awarded a Capacity Supply Obligation in an Annual Capacity Auction, except as follows:

(i) If the capacity for which a Capacity Offer Floor Price has been determined does not clear the first Annual Capacity Auction into which it is offered, the Lead Market Participant may submit a request to the Internal Market Monitor to recalculate the Capacity Offer Floor Price for a subsequent Annual Capacity Auction if either (1) the cost or expected revenue assumptions for the resource have changed from those same assumptions reflected in the most recent submission of information pursuant to Section III.A.21.1.5(a) in a way that will impact the Capacity Offer Floor Price determination or (2) the Capacity Offer Floor Price had been set to the Capacity Auction Offer Price Cap. The request must be made by the submission deadline for the subsequent Annual Capacity Auction set forth in Section III.A.21.1.5(c) and must include all of the information and documentation required by

Section III.A.21.1.5(a). If the request is made on the grounds of a change in cost or expected revenue assumptions, the request must clearly and specifically identify the changed assumptions and the supporting documentation for such assumptions, and must explain how the changed assumptions will impact the Capacity Offer Floor Price calculation. The Internal Market Monitor, at its discretion, may reject a request to recalculate that does not clearly and specifically identify the changed assumptions or the supporting documentation for such assumptions, or explain the impact on the Capacity Offer Floor Price calculation.

(ii) If the capacity satisfies the requirements of Section III.A.21.1.1, then the capacity will not be subject to a Capacity Offer Floor Price, even if the Internal Market Monitor previously determined a Capacity Offer Floor Price for the capacity.

(iii) If the capacity satisfies the requirements of Section III.A.21.1.5(g), then the capacity will not be subject to a Capacity Offer Floor Price, even if the Internal Market Monitor previously determined a Capacity Offer Floor Price for the capacity.

III.A.22. Supply-Side Market Power Review for the Capacity Market

III.A.22.1. Capacity Market Offer Requirement.

(a) With the exception of resources for which the ISO has accepted a Deactivation Notification that will be in effect for the relevant Capacity Commitment Period, a resource that has previously held a Capacity Supply Obligation or has had a Capacity Offer submitted on its behalf in a prior Annual Capacity Auction is required to participate in the qualification process for the Annual Capacity Auction as described in Sections III.15.2 and III.15.3.

(b) A resource that has not previously held a Capacity Supply Obligation or has not had a Capacity Offer submitted on its behalf in a prior Annual Capacity Auction is required to participate in the qualification process for the Annual Capacity Auction as described in Sections III.15.2 and III.15.3 if the resource (1) has CNR Capability at the time of the Qualification Data Submission Deadline and (2) is in commercial operation or has a Commercial Operation Date in its interconnection agreement earlier than April 1 of the same calendar year as the Annual Capacity Auction.

(c) A Capacity Offer must be submitted to the ISO during the Annual Capacity Auction Offer Window for a resource that participates in the qualification process for the Annual Capacity Auction as described in Sections III.15.2 and III.15.3 and receives an Annual Qualified Capacity greater than 0 MW. The Capacity Offer must include a total quantity that is equal to the resource's Annual Qualified Capacity.

(d) If a Capacity Offer is not submitted to the ISO during the Annual Capacity Auction Offer Window for a resource subject to subsection (c), the ISO shall enter a Capacity Offer for the resource into the Annual Capacity Auction with the resource's Annual Qualified Capacity priced at either (i) $0.00/kW-month or (ii) for any capacity subject to a Capacity Offer Floor Price pursuant to Section III.A.21 supplied by the resource, the Capacity Offer Floor Price.

III.A.22.2. Capacity Offer Price Review for Economic Withholding.

The Internal Market Monitor shall review Proposed Capacity Offers from resources that will submit Capacity Offers in the Annual Capacity Auction as described in this Section III.A.22.2.

III.A.22.2.1. Capacity Offer Price Threshold.

For each Annual Capacity Auction, a Capacity Offer Price Threshold shall be calculated as described below in this Section III.A.22.2.1 and shall be published to the ISO's website no later than one month before the Capacity Offer Review Submission Deadline. This publication shall include the preliminary value calculated pursuant to subsection (a) below, whether the preliminary value was constrained by either of the limitations described in subsection (b) below, the margin value as calculated pursuant to subsection (c) below, and the final value as calculated pursuant to subsection (d) below.

(a) Subject to the limitations described in subsection (b) and to subsection (e) below, a preliminary value of the Capacity Offer Price Threshold shall be calculated as the average of: (i) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone from the immediately preceding Annual Capacity Auction (provided, however, that if there is a second run of the primary auction-clearing process pursuant to Section III.15.4.2.4, the resulting Rest-of-Pool Capacity Zone clearing price from that run shall be used instead); and (ii) the price at which the total amount of capacity clearing in the immediately preceding Annual Capacity Auction intersects the System-Wide Capacity Demand Curve for the upcoming Annual Capacity Auction that is filed with the

Commission pursuant to Section III.12.3(a) in advance of the upcoming Annual Capacity Auction.

(b) The preliminary value of the Capacity Offer Price Threshold shall not be higher than 75 percent of the Net CONE value for the upcoming Annual Capacity Auction. The preliminary value of the Capacity Offer Price Threshold shall not be lower than 75 percent of the clearing price applicable pursuant to (a)(i) of this Section III.A.22.2.1, except as needed to ensure that it is not higher than 75 percent of the Net CONE value for the upcoming Annual Capacity Auction.

(c) A margin value shall be calculated using the following formula:

$$Margin = \$1/kW\text{-}month \times \left[\frac{(0.75 \times Net\ CONE_{upcoming\ ACA}) - COPT_{preliminary}}{(0.75 \times Net\ CONE_{upcoming\ ACA})}\right]$$

(d) The final value of the Capacity Offer Price Threshold for the upcoming Annual Capacity Auction shall be equal to the preliminary value of the Capacity Offer Price Threshold calculated pursuant to Sections III.A.22.2.1(a) and III.A.22.2.1(b) plus the margin value calculated pursuant to Section III.A.22.2.1(c).

(e) For the purpose of determining a preliminary value of the Capacity Offer Price Threshold for the Annual Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, the "immediately preceding Annual Capacity Auction" shall mean the Forward Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2027.

III.A.22.2.2. Applicability of Capacity Offer Price Review.

(a) Except with regard to capacity subject to a Capacity Offer Floor Price pursuant to Section III.A.21 and Capacity Offers that will meet the requirements set forth in subsection (d) below, a Lead Market Participant that seeks to submit a Capacity Offer that specifies prices above the Capacity Offer Price Threshold for the Annual Capacity Auction must submit a Proposed Capacity Offer to the Internal Market Monitor for review pursuant to Section III.A.22.2.3 and must include the additional documentation described in that section. With the submission of a Proposed Capacity Offer, the Lead Market Participant must notify the ISO if the resource for which the Proposed Capacity Offer is submitted will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests) if it is not awarded a Capacity Supply Obligation for the Capacity Commitment Period.

(b) The Proposed Capacity Offer and all documentation required for the Internal Market Monitor's review must be submitted no later than the Capacity Offer Review Submission Deadline established for the Annual Capacity Auction. If a Lead Market Participant does not submit a Proposed Capacity Offer and the required supporting documentation to the Internal Market Monitor by the Capacity Offer Review Submission Deadline, the Capacity Offer submitted for the resource during the Annual Capacity Auction Offer Window must not specify any prices above the Capacity Offer Price Threshold.

(c) A price in a Capacity Offer specified for capacity subject to a Capacity Offer Floor Price pursuant to Section III.A.21 is not subject to the Internal Market Monitor's review pursuant to Section III.A.22.2.3, but the specified price may only be greater than the Capacity Offer Floor Price if the price is below the Capacity Offer Price Threshold. If the Capacity Offer Floor Price is at or above the Capacity Offer Price Threshold, the specified price must equal the Capacity Offer Floor Price.

(d) Notwithstanding subsection (a) above, a Lead Market Participant that seeks to submit a Capacity Offer that specifies a price above the Capacity Offer Price Threshold for the Annual Capacity Auction is not required to submit a Proposed Capacity Offer if (i) the Capacity Offer will not contain more than one price-quantity pair that has a specified price above the Capacity Offer Price Threshold and (ii) the difference between the MW quantity of such price-quantity pair and the MW quantity of the price-quantity pair that specifies the next lowest price is equal to or less than the ambient air condition MW verified through the process set forth in Section III.15.2.1.5. For the purposes of Sections III.15.4.1, any Capacity Offer that qualifies for this exemption from the Proposed Capacity Offer submission requirement shall be deemed to have met the requirements set forth in (i) through (iii) of Section III.15.4.1(e) and to have been determined an Allowable Capacity Offer Price of $0.01/kW-month greater than the Capacity Auction Offer Price Cap for the price-quantity pair. Such price-quantity pair will not be subject to the mitigation set forth in Sections III.A.22.2.4(c) and (d). Nothing in this subsection (d), however, shall limit or prevent the Internal Market Monitor from reviewing any ambient air condition adjustment or any Capacity Offer that qualifies for the exemption set forth in this subsection (d) for the potential exercise of market power, or to request additional information from the Lead Market Participant submitting the Capacity Offer to enable the Internal Market Monitor to make such a determination and take any appropriate steps.

III.A.22.2.3. Review of Capacity Offer Prices Exceeding Threshold.

(a) The Internal Market Monitor shall review each Proposed Capacity Offer with a price above the Capacity Offer Price Threshold to determine whether the offer is consistent with the following: (1) the resource's net going forward costs; (2) reasonable expectations about the resource's Capacity Performance Payments; (3) reasonable risk premium assumptions; and (4) the resource's reasonable opportunity costs, all as determined pursuant to this Section III.A.22.2.3. Sufficient documentation and information about each offer component must be included in the Section III.A.22.2.2(a) submittal to allow the Internal Market Monitor to make the requisite determinations about each cost component. The Section III.A.22.2.2(a) submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of its content, including reported costs, the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a resource with a Capacity Supply Obligation, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments, cash flows, opportunity costs, and risk premiums, and shall be subject to audit upon request by the ISO. The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the other existing or potential new resources controlled by the Lead Market Participant) at any time to address any questions or concerns regarding the data submitted, as appropriate. In determining the consistency of Proposed Capacity Offer prices with the foregoing cost components, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio. In its review of the Proposed Capacity Offer, the Internal Market Monitor shall treat ambient air condition MW verified through the process set forth in Section III.15.2.1.5, if any, as physically unavailable and make its determinations pursuant to this Section III.A.22.2.3 accordingly.

(b) The Internal Market Monitor shall review each Proposed Capacity Offer and, after due consideration and consultation with the Lead Market Participant, as appropriate, shall develop Cost-Based Reference Prices for comparison with the prices specified in the Proposed Capacity Offer that are above the Capacity Offer Price Threshold. The Internal Market Monitor shall calculate the Cost-Based Reference Prices in a manner that is consistent with the sum of the resource's net going forward costs plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable risk premium assumptions plus reasonable opportunity costs. The Internal Market Monitor's comparison of the Cost-Based Reference Prices to the prices specified in the Proposed Capacity Offer will result in Allowable Capacity Offer Prices as follows:

(i) For each price-quantity pair in the Proposed Capacity Offer that specifies a price above the Capacity Offer Price Threshold, the Internal Market Monitor shall calculate a Cost-Based Reference Price for the MW quantity specified in the price-quantity pair.

(ii) If the price specified in the price-quantity pair of the Proposed Capacity Offer is equal to or less than 110 percent of the Cost-Based Reference Price for such price-quantity pair, then the Allowable Capacity Offer Price for the price-quantity pair shall be equal to the price specified for the price-quantity pair. If the price specified for the price-quantity pair is more than 110 percent of the Cost-Based Reference Price, then the Allowable Capacity Offer Price for the price quantity pair shall be equal to the Cost-Based Reference Price.

(iii) If replacement of the prices specified for price-quantity pairs in the Proposed Capacity Offer with the Allowable Capacity Offer Prices determined pursuant to (i) and (ii) would result in a Capacity Offer that does not comply with the requirements of Section III.15.4.1(d), the Internal Market Monitor, after consultation with the Lead Market Participant, may adjust the Allowable Capacity Offer Price for any price-quantity pair as necessary to ensure that the Proposed Capacity Offer, if submitted pursuant to Section III.15.4.1 and mitigated pursuant to Section III.A.22.2.4(c), would comply with the requirements of Section III.15.4.1(d).

(c) If the Internal Market Monitor establishes an Allowable Capacity Offer Price for a price-quantity pair that does not equal the price specified by the Lead Market Participant for the price-quantity pair in the Proposed Capacity Offer, an explanation of the Allowable Capacity Offer Price based on the Internal Market Monitor review shall be provided to the Lead Market Participant at the time the Internal Market Monitor notifies the Lead Market Participant of the results of the Internal Market Monitor's Proposed Capacity Offer price review. Such explanation shall explain the Internal Market Monitor's determinations with respect to the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor.

III.A.22.2.3.1. Net Going Forward Costs.

The Lead Market Participant for a resource that submits a Proposed Capacity Offer with a price above the Capacity Offer Review Threshold shall report expected net going forward costs for the applicable Capacity Commitment Period in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. A Proposed Capacity Offer price shall be evaluated for consistency with the capacity's net going forward costs based on a review of the data submitted in the following formula:

$$\textit{Net Going Forward Costs} = \frac{(GFC - IMR)}{(CQ_{Summer,}\ kW) \times (12\ \textit{months})}$$

Where:

GFC = annual going forward costs, in dollars. These are the expected costs and capital expenditures that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a resource with a Capacity Supply Obligation during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Proposed Capacity Offer that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period if it is not awarded a Capacity Supply Obligation for the Capacity Commitment Period. Expenses, including financial obligations, incurred prior to the capacity auction that cannot be recovered, reimbursed, compensated, waived, or cancelled should the resource not be awarded a Capacity Supply Obligation are considered unavoidable and shall not be included. The expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area may be included for Import Capacity Resources.

$CQ_{Summer}kW$ = capacity, in kilowatts, for which the price specified in the Proposed Capacity Offer is above the Capacity Offer Price Threshold. In no case shall this value exceed the resource's summer Qualified Capacity.

IMR = expected annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Proposed Capacity Offer that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be calculated by subtracting all submitted cost data representing the cumulative expected cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the resource's total ISO market revenues. In the case of a resource that has indicated that the resource will be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00.

III.A.22.2.3.2. Expected Capacity Performance Payments.

The Lead Market Participant for a resource that submits a Proposed Capacity Offer with a price above the Capacity Offer Review Threshold shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.A.22.2.3.3. Risk Premium.

The Lead Market Participant for a resource that submits a Proposed Capacity Offer with a price above the Capacity Offer Review Threshold shall also provide documentation separately detailing any risk premium included in the price. This documentation must address all components of physical and financial risk reflected in the price, including, for example, catastrophic events, a higher-than-expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs described in Section III.A.22.2.3.1 may be included in this risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the Annual Capacity Market is consistent with the participant's corporate risk management practices.

III.A.22.2.3.4. Opportunity Costs.

To the extent that a Capacity Resource submitting a Proposed Capacity Offer with a price above the Capacity Offer Review Threshold has additional opportunity costs that are not reflected in the net going forward costs, net present value of expected cash flows, expected Capacity Performance Payments, discount rate, or risk premium components of the price, the Lead Market Participant must include in the submission to the Internal Market Monitor evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.15.3.6, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.A.22.2.3.5. Review as Applied to Stations having Common Costs.

Where a resource at a Station having Common Costs elects to submit a Proposed Capacity Offer with a price above the Capacity Offer Review Threshold, the provisions of this Section III.A.22.2.3.5 shall apply.

(a) **Submission of Cost Data.** In addition to the information required elsewhere in this Section III.A.22.2.3, a Proposed Capacity Offer submitted by a resource that is associated with a Station having Common Costs must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

(b) **Internal Market Monitor Review of Stations having Common Costs.** The Internal Market Monitor will review each price specified in the Proposed Capacity Offer that is above the Capacity Offer Price Threshold from a resource that is associated with a Station having Common Costs pursuant to the following methodology:

(i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.

(ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the asset offer order.

(iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive failure to clear the Annual Capacity Auction by each individual asset in asset offer order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of Capacity Offer price-quantity pairs as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The Capacity Offer price-quantity pairs of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable price-quantity pair for use in the Annual Capacity Auction.

The Internal Market Monitor will compare a Capacity Offer price developed using the adjusted composite costs to the price specified in the Proposed Capacity Offer submitted by the resource that is associated with a Station having Common Costs and determine an Allowable Capacity Offer Price as described in Section III.A.22.2.3(b).

III.A.22.2.3.6. Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall use the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent, when relevant to its review pursuant to this Section III.A.22.2.3.

Age of Existing Resource (years)	**Remaining Life (years)**	**Annual Rate of Capital Cost Recovery**
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, along with its documentation submitted pursuant to Section III.A.22.2.2(b). The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource's annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{\mathit{Cost\ Of\ Capital}}{(1-(1+\mathit{CostOfCapital})^{-\mathit{RemainingLife}})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the resource, based on the age of the resource, as indicated in the table above.

III.A.22.2.4 Results of Capacity Offer Price Review.

(a) Concurrent with the Seasonal Qualified Capacity Notification Date for the Annual Capacity Auction, the ISO shall notify the Lead Market Participant that submitted a Proposed Capacity Offer concerning the result of the Internal Market Monitor's Proposed Capacity Offer price review conducted pursuant to Section III.A.22.2.3 and include the information described in Section III.A.22.2.3(c).

(b) After the notification described in subsection (a), the Internal Market Monitor may redetermine any Allowable Capacity Offer Price, as necessary, to reflect changes in a resource's Seasonal Qualified Capacity Values that occur after the Seasonal Qualified Capacity Notification Date or to correct any errors in the initial determination of the Allowable Capacity Offer Price. The Internal Market Monitor shall notify the Lead Market Participant of any such redetermination on the same date as any notifications made by the ISO pursuant to Section III.15.2.7(d).

(c) For resources for which an Allowable Capacity Offer Price was established pursuant to Section III.A.22.2.3, the ISO shall replace a price specified in a price-quantity pair of the resource's Capacity Offer in the Annual Capacity Auction with a price as set forth in subsection (d), under the following circumstances:

(i) the resource is associated with a pivotal supplier, as determined pursuant to the pivotal supplier test set forth in Section III.A.23; and

(ii) the price specified in the price-quantity pair exceeds the greater of the Allowable Capacity Offer Price established for such price-quantity pair and the Capacity Offer Price Threshold determined pursuant to Section III.A.22.2.1.

(d) For the purposes of subsection (c), the ISO shall replace a price specified in a price-quantity pair of the Capacity Offer with the greater of (i) the Allowable Capacity Offer Price established for the price-quantity pair and (ii) the Capacity Offer Price Threshold.

III.A.22.3. Request for Additional Capacity Cost Recovery.

If as a result of mitigation applied to a Capacity Offer pursuant to Section III.A.22.2.4(c) a Lead Market Participant believes that it will not recover the costs to its Capacity Resource of meeting the Capacity Supply Obligation for the Capacity Commitment Period, as reflected in the Capacity Offer submitted for the resource, the Lead Market Participant may submit a filing to the Commission pursuant to Section 205 of the Federal Power Act in accordance with this Section III.A.22.3.

III.A.22.3.1. Threshold Conditions for Filing a Request.

To be eligible to make a Section 205 filing pursuant to this Section III.A.22.3, the following threshold conditions must have been met:

(a) the Capacity Offer submitted by the Lead Market Participant for the Capacity Resource in the Annual Capacity Auction must have at least one price-quantity pair that was submitted as part of a Proposed Capacity Offer and for which the Internal Market Monitor determined an Allowable Capacity Offer Price pursuant to Section III.A.22.2.3;

(b) the price specified in such price-quantity pair must have been replaced pursuant to Section III.A.22.2.4(c) prior to entry of the Capacity Offer into the Annual Capacity Auction; and

(c) some portion of the MW quantity specified in such price-quantity pair that is also included in the Capacity Offer's Above-Threshold Offer Segment must have been awarded a Capacity Supply Obligation in the Annual Capacity Auction.

III.A.22.3.2. Relief Available Through Filing.

(a) The Section 205 filing may request the following relief from the Commission:

(i) additional costs associated with the Capacity Supply Obligation awarded to the Capacity Resource in the Annual Capacity Auction, to be paid on a kW-month basis, at a price that is measured as the positive difference between (1) the lowest price specified in the Capacity Offer for the amount of MW of the Capacity Supply Obligation for which the Lead Market Participant seeks additional cost recovery and (2) the Capacity Clearing Price applicable to the Capacity Supply Obligation; and

(ii) regulatory costs associated with the filing.

(b) A Lead Market Participant may not request a cost recovery rate that exceeds a rate calculated in accordance with subsection (a)(i). Notwithstanding subsection (a)(i), the Commission is not required to use a price specified in the Capacity Offer for the determination of a cost recovery rate if the Capacity Resource’s costs of meeting its Capacity Supply Obligation are, on a kW-month basis, lower than such price.

III.A.22.3.3. Timing of Filing.

A Section 205 filing made pursuant to this Section III.A.22.3 must be made within sixty days after the ISO publicly publishes the results of the Annual Capacity Auction in accordance with Section III.15.4.3.

III.A.22.3.4. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include the following:

(a) the Proposed Capacity Offer, all documentation and information submitted to the Internal Market Monitor pursuant to Section III.A.22.2, and any additional documentation and information relevant to the Proposed Capacity Offer that was submitted to the Internal Market Monitor during any consultation with the Internal Market Monitor before, during, or after the formal review process described in Sections III.A.22.2 and III.A.22.3;

(b) the Internal Market Monitor’s notification pursuant to Section III.A.22.2.4(a) and any explanation provided as part of that notification pursuant to Section III.A.22.2.3(c);

(c) all price-quantity pairs and other parameters in the Capacity Offer submitted to the ISO for entry into the Annual Capacity Auction;

(d) identification of the price-quantity pairs contained in the Capacity Offer that the Lead Market Participant claims have been improperly mitigated pursuant to Section III.A.22.2.4(c);

(e) identification of the amount of MW of the Capacity Supply Obligation for which the Lead Market Participant seeks additional cost recovery;

(f) an explanation as to the alleged error committed by the Internal Market Monitor in determining the Cost-Based Reference Price for the MW amount identified pursuant to subsection (e);

(g) the Internal Market Monitor's written response to the request for relief, provided pursuant to Section III.A.22.3.5; and

(h) all requested regulatory costs in connection with the filing.

III.A.22.3.5. Review by Internal Market Monitor Prior to Filing.

Within twenty days after the ISO publicly publishes the results of the Annual Capacity Auction, a Lead Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.22.3 shall submit to the Internal Market Monitor a complete, advance copy of the filing with all of the material described in Section III.A.22.3.4, with the exception of the material described in Section III.A.22.3.4(g). Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the request for additional cost recovery. The Lead Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing, as described in Section III.A.22.3.4(g).

III.A.22.3.6. Payments and Charges Related to the Additional Cost Recovery.

(a) In the event that the Commission accepts a filing for cost recovery under this section, the ISO shall adjust the Capacity Resource's monthly capacity payment calculated pursuant to Section III.15.8.1.1(a) to reflect the additional cost recovery rate for the portion of the Capacity Resource's Capacity Supply Obligation to which additional cost recovery applies. With respect to monthly capacity payments made prior to implementation of a Commission-accepted additional cost recovery rate, the ISO shall issue a single lump sum payment reflecting the additional cost recovery rate.

(b) The ISO shall allocate costs associated with payments made pursuant to subsection (a) in accordance with the cost allocation provisions in Section III.15.8.5.1 that apply to Annual Capacity Auction costs. Charges for the lump sum payment made pursuant to subsection (a) shall be determined in a way that is consistent with a Market Participant's Capacity Load Obligation during each Obligation Month covered by the lump sum payment.

(c) With respect to any regulatory costs accepted by the Commission, the ISO shall apportion the sum total of such regulatory costs equally among the twelve months of the Capacity Commitment Period. Each monthly amount shall be added to the Capacity Resource's monthly capacity payment, and any monthly amounts applicable to monthly capacity payments made prior to implementation of a Commission-accepted additional cost recovery rate shall be added to the lump sum payment set forth in subsection (a). The ISO shall allocate costs associated with payments of such regulatory costs consistent with the allocation methodology set forth in subsection (b).

III.A.23. Pivotal Supplier Test for the Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to conducting the Annual Capacity Auction at the system level and for each import-constrained Capacity Zone. For the purpose of performing the pivotal supplier test as described in this Section III.A.23.1, the Capacity Resources that will be included in the calculations described herein are the Capacity Resources that will be entered into the Annual Capacity Auction for which the test is being performed.

A Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's Annual Qualified Capacity, the ability to meet the relevant requirement is less than the requirement.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

III.A.23.1.1. System-Level Requirement.

At the system level, the ability to meet the relevant requirement is the sum of the following:

(a) The total Annual Qualified Capacity from all Generating Capacity Resources and Demand Capacity Resources in the Rest-of-Pool Capacity Zone;

(b) For each modeled import-constrained Capacity Zone, the greater of:

(1) the total Annual Qualified Capacity from all Generating Capacity Resources and Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of Annual Qualified Capacity from Import Capacity Resources over the interface, and;

(2) the Local Sourcing Requirement of the import-constrained Capacity Zone;

(c) For each modeled nested export-constrained Capacity Zone, the lesser of:

(1) the total Annual Qualified Capacity from all Generating Capacity Resources and Demand Capacity Resources within the nested export-constrained Capacity Zone plus, for each external interface connected to the nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of Annual Qualified Capacity from Import Capacity Resources over the interface, and;

(2) the Maximum Capacity Limit of the nested export-constrained Capacity Zone;

(d) For each modeled export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, the lesser of:

(1) the total Annual Qualified Capacity from all Generating Capacity Resources and Demand Capacity Resources within the export-constrained Capacity Zone, excluding the total Annual Qualified Capacity from Generating Capacity Resources and Demand Capacity Resources within a nested export-constrained Capacity Zone, plus, for each external interface connected to the export-constrained Capacity Zone that is not included in any nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of Annual Qualified Capacity from Import Capacity Resources over the interface, excluding the contribution from any nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;

(2) the Maximum Capacity Limit of the export-constrained Capacity Zone minus the contribution from any associated nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c);

(e) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of:

(1) the capacity transfer limit of the interface (net of tie benefits), and;

(2) the total amount of Annual Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.1.2. Import-Constrained Capacity Zone Requirement.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

(a) The total Annual Qualified Capacity from all Generating Capacity Resources and Demand Capacity Resources located within the import-constrained Capacity Zone; and

(b) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of Annual Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

Annual Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

(a) If the removal of a supplier's Annual Qualified Capacity in an export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1.1(c) or Section III.A.23.1.1(d) for that export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.

(b) If the removal of a supplier's Annual Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1.1(e) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(c) If the removal of a supplier's Annual Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1.2 for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(d) If a supplier whose only Annual Qualified Capacity is a single capacity resource with a Capacity Offer that (i) is not subject to rationing, and (ii) contains only one price-quantity pair for the entire Annual Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers that are determined to be pivotal and subject to the mitigation described in Section III.A.22.2.4(c) as soon as practicable after the close of the Annual Capacity Auction Offer Window and before the Annual Capacity Auction results are determined.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the Annual Qualified Capacity of a supplier includes the capacity of Generating Capacity Resources, Demand Capacity Resources, and Import Capacity Resources that is controlled by the supplier or its Affiliates.

For purposes of determining the Annual Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Deactivation Notification Package Submission and Review.

III.A.24.1. Deactivation Notifications Requiring Workbook Submission and Review.

A Lead Market Participant seeking to permanently remove all or part of a resource from the Annual Capacity Market or from all New England Markets must follow the Deactivation Notification process pursuant to Section II.52, including the timely and complete submission of a Deactivation Notification Package. For each Deactivation Notification representing the deactivation of greater than 20 MW, the Deactivation Notification Package shall include the cost workbooks and supporting materials described in Section III.A.24.2 for review by the Internal Market Monitor. If more than one Deactivation Notification is submitted by a single Lead Market Participant or its Affiliates (as used in Section III.A.24.6) and the sum of all such Deactivation Notifications in aggregate is greater than 20 MW, then the Lead Market

Participant must timely submit each such Deactivation Notification Package, including the cost workbooks and supporting materials described in Section III.A.24.2, as if each deactivation were greater than 20 MW. The Internal Market Monitor has no obligation to review a Deactivation Notification Package if the Deactivation Notification provides notice of either: (a) deactivation of the only resource controlled by a Lead Market Participant or its Affiliates participating in the Annual Capacity Market; or (b) deactivation of all resources controlled by a Lead Market Participant or its Affiliates participating in the Annual Capacity Market, where the term "control" has the meaning set forth in Section III.A.24.6.

Resources requiring review under Section III.A.24.1 that deactivate without submitting the complete information required by Section III.A.24.2 by the Deactivation Notification Deadline set forth in Section II.52.1 may be subject to referral to the Commission's Office of Enforcement in accordance with Section III.A.19 if the Internal Market Monitor has reason to believe a Market Violation has occurred. In instances where a resource deactivates without submitting the complete information required by Section III.A.24.2, the Internal Market Monitor will determine the Proxy Capacity Offer of the resource pursuant to Section III.A.24.7 and include the Proxy Capacity Offer in the deactivation determinations filing pursuant to Section III.A.24.9.

III.A.24.2. Submission of Cost Workbooks and Supporting Materials.

Lead Market Participants submitting a Deactivation Notification Package subject to review under Section III.A.24.1 shall submit completed cost workbooks based on the latest Deactivation Notification cost workbooks posted to the ISO's website. The submitted cost workbooks shall include or be accompanied by sufficient documentation and information about each cost workbook component to allow the Internal Market Monitor to make the requisite determinations regarding their validity and the economic viability of the deactivating resource. Lead Market Participants submitting a Deactivation Notification Package shall include in their submission identifying information relating to all Annual Qualified Capacity that the Lead Market Participant and its Affiliates control (as that term is defined in Section III.A.24.6) including all capacity the control of which it has contracted to a third party.

Lead Market Participants may elect to submit the relevant cost workbooks and supporting materials for a completeness determination by the Internal Market Monitor no earlier than 90 days, but no later than 30 days, before the Deactivation Notification Deadline. No later than ten business days before the Deactivation Notification Deadline, the Internal Market Monitor shall notify those Lead Market Participants submitting materials for a completeness determination that either: (a) the submission has been determined to be complete; or (b) the submission has been determined to be incomplete, and identifying any aspects of the workbook or supporting materials that are deemed incomplete. Submission of a cost workbook and supporting materials for a completeness determination is optional and does not eliminate the requirement to submit a Deactivation Notification and Deactivation Notification Package on or immediately before the Deactivation Notification Deadline.

III.A.24.3. Internal Market Monitor Review of Deactivation Notification Package.

The Internal Market Monitor shall review all Deactivation Notification Packages requiring review pursuant to Section III.A.24.1 that the Internal Market Monitor determines contain a complete submission of cost workbooks and supporting material submitted on or before the Deactivation Notification Deadline for the relevant Capacity Commitment Period. The Internal Market Monitor is under no obligation to review Deactivation Notifications that it deems to be incomplete at the time of the Deactivation Notification Deadline due to incomplete cost workbooks and supporting materials.

The Internal Market Monitor shall review each timely-submitted and complete Deactivation Notification Package requiring review pursuant to Section III.A.24.1 to determine whether the economic basis for the deactivation is consistent with: (1) the net present value of the resource's expected cash flows (as determined pursuant to Section III.A.24.4.1); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.A.24.4.2); and (3) the resource's reasonable opportunity costs (as determined pursuant to Section III.A.24.4.3). The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the submission is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, and reasonable opportunity costs. In making this determination, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the other existing or potential new resources controlled by the Lead Market Participant) after the Deactivation Notification Deadline for resources requiring review under Section III.A.24 to address any questions or concerns regarding the data submitted, as appropriate.

III.A.24.4. Net Present Value of Expected Cash Flows.

For those Capacity Resources subject to Internal Market Monitor review pursuant to Section III.A.24.1, the net present value of a Capacity Resource's expected cash flows shall be determined as described in this Section III.A.24.4.

III.A.24.4.1. Net Present Value of Expected Cash Flows Formula.

The Lead Market Participant for a Capacity Resource that submits a Deactivation Notification that is to be reviewed by the Internal Market Monitor shall report all expected costs, revenues, prices, discount rates and capital expenditures in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. The Internal Market Monitor will review the Lead Market Participant's submitted data to ensure that it is consistent with overall market conditions and reflects expected values. The Internal Market Monitor will adjust any data that are inconsistent with overall market conditions or do not reflect expected values. The Internal Market Monitor shall enter all relevant expected costs, revenues, prices, discount rates and capital expenditures into a capital budgeting model and shall determine the net present value of the Capacity Resource's expected cash flows as follows:

The net present value of the Capacity Resource's expected cash flows is equal to (i) the net present value of the Capacity Resource's net annual expected cash flows over the resource's remaining economic life (as determined below) plus the net present value of the resource's expected terminal value, using the resource's discount rate, divided by (ii) the product of the resource's Qualified Capacity (in kilowatts) and 12 months.

The Capacity Resource's net annual expected cash flow for the first Capacity Commitment Period of the resource's remaining economic life (i.e., the Capacity Commitment Period associated with the Deactivation Notification) is the resource's expected annual net operating profit, including expected capacity revenues, less its expected capital expenditures in the Capacity Commitment Period.

The Capacity Resource's net annual expected cash flow for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life is the resource's expected annual net operating profit less its expected capital expenditures in the Capacity Commitment Period.

Where:

Expected net operating profit, in dollars, is the Lead Market Participant's expected annual profit that might otherwise be avoided or not accrued if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period. Expected labor, maintenance, taxes, insurance, administrative and other normal expenses that can be avoided or not incurred if the resource is deactivated may be included. Service of debt is not an avoidable cost and may not be included.

Expected capacity revenues, in dollars, are the forecasted annual expected capacity revenues based on the Lead Market Participant's forecasted expected capacity prices for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life. The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the forecasted expected capacity prices. The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions about expected resource additions, resource deactivations, estimated Installed Capacity Requirements, estimated Local Sourcing Requirements, expected market conditions, and any other assumptions used to develop the forecasted expected capacity prices in each Capacity Commitment Period.

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the forecasted expected capacity prices, the Internal Market Monitor will replace the Lead Market Participant's forecasted expected capacity prices with the Internal Market Monitor's estimate thereof in each of the subsequent Capacity Commitment Periods of the resource's remaining economic life.

Expected capital expenditures, in dollars, are the Lead Market Participant's expected capital investments that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Periods.

Expected terminal value, in dollars, for resources with five years or less of remaining economic life, is the Lead Market Participant's expected revenue less expected costs associated with deactivating the resource. For resources with more than five years of remaining economic life, the expected terminal value in the fifth year of the evaluation period is the Lead Market Participant's expected revenue less expected costs associated with deactivating the resource at the end of the resource's economic life plus the net present value of the Capacity Resource's net annual expected cash flows from the sixth year of the evaluation period through the end of the resource's remaining economic life, using the resource's discount rate.

Discount rate is a value reflecting the Lead Market Participant's weighted average cost of capital for the Capacity Resource adjusted to reflect the risk to cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.A.24.4.

The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the weighted average cost of capital for the Capacity Resource adjusted for risk. The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions associated with the cost of capital, risks and any other assumptions used to develop the weighted average cost of capital for the Capacity Resource adjusted for risk. If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the weighted average cost of capital for the Capacity Resource adjusted for risk, the Lead Market Participant has included risks not associated with cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.A.24.4 or the Lead Market Participant has submitted costs, revenues, capital expenditures or prices that are not reflective of expected values, the Internal Market Monitor will replace the Lead Market Participant's discount rate with a value determined by the Internal Market Monitor.

The Internal Market Monitor shall calculate the Capacity Resource's remaining economic life, using evaluation periods ranging from one to five years with year one being the Capacity Commitment Period associated with the Deactivation Notification. For each evaluation period, the Internal Market Monitor will calculate the net present value of (a) the annual expected net operating profit minus annual expected capital expenditures assuming the Capacity Clearing Price for the first year is equal to the Internal Market Monitor's estimate of the Capacity Auction Offer Price Cap and (b) the expected terminal value of the resource at the end of the given evaluation period. The economic life is the evaluation period in which a resource's net present value is maximized.

III.A.24.4.2. Expected Capacity Performance Payments.

The Lead Market Participant for a Capacity Resource that submits a Deactivation Notification that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.A.24.4.3. Opportunity Costs.

To the extent that a Capacity Resource submitting Deactivation Notification has additional opportunity costs that are not reflected in the net going forward costs, net present value of expected cash flows, expected Capacity Performance Payments, discount rate, or risk premium components of the bid, the Lead Market Participant must include evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.15.3.6, capital projects required to operate the plant as a capacity resource or for other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.A.24.4.4. Stations Having Common Costs.

Deactivation Notifications submitted by a Generating Capacity Resource that is associated with a Station having Common Costs and seeking to deactivate must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs. The Internal Market Monitor will review each Deactivation Notification from a Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

(i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.

(ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred deactivation order.

(iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive deactivation of each individual asset in preferred deactivation order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically nonincreasing set of prices as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The price of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable bid for use in the Capacity Auction.

The Internal Market Monitor will compare a price developed using the adjusted composite costs to the Deactivation Notification submitted by the Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted price is greater than the price developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will establish an Internal Market Monitor-calculated price as described in Section III.A.24.5 and, if the resource is determined to be deactivating to the benefit of a portfolio pursuant to III.A.24.6, the Internal Market Monitor shall use the Internal Market Monitor calculated price as the Proxy Capacity Offer Price pursuant to III.A.24.7.

III.A.24.5. Conduct Test.

The Internal Market Monitor shall review those Deactivation Notifications submitted pursuant to Section III.A.24.1 to determine whether the economic basis for a Deactivation Notification and associated cost workbooks are consistent with the reasonable net present value of the resource's expected cash flows, reasonable expectations about the resource's Capacity Performance Payments, and the resource's reasonable opportunity costs. After due consideration and consultation with the Lead Market Participant, as appropriate, the Internal Market Monitor shall develop a first-year break-even price based on the cost workbooks and supporting materials submitted by the Lead Market Participant. The Internal Market Monitor shall also calculate a first-year break-even price based on the Internal Market Monitor's reasonable expectations regarding net present value of the resource's expected cash flows, the resource's Capacity Performance Payments, and the resource's opportunity costs. If the first-year expected Capacity Clearing Price submitted by the Lead Market Participant is more than 10% greater than the first-year break-even price calculated based on the Internal Market Monitor's reasonable expectations regarding the net present value of the resource's expected cash flows, the resource's Capacity Performance Payments, and the resource's opportunity costs, then that resource fails the conduct test. For those resources failing the conduct test, the Internal Market Monitor shall perform a further review of the Lead Market Participant's portfolio pursuant to III.A.24.6. Resources that do not fail the conduct test shall deactivate consistent with the terms of their Deactivation Notification unless delaying deactivation pursuant to Section II.53.

III.A.24.6. Portfolio Benefit Test.

The portfolio benefit test is performed for each Lead Market Participant submitting a Deactivation Notification subject to Internal Market Monitor review that has failed the conduct test set forth in Section III.A.24.5. The test will be performed as follows:

If

i. The annual capacity revenue from the Lead Market Participant's total Annual Qualified Capacity, not including the Annual Qualified Capacity associated with the Deactivation Notification, is greater than

ii. the annual capacity revenue from the Lead Market Participant's total Annual Qualified Capacity, including the Annual Qualified Capacity associated with the Deactivation Notifications for resources controlled by the Lead Market Participant that failed the conduct test as calculated pursuant to subsection v. below, then

iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the portfolio benefit test.

Where,

iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total Annual Qualified Capacity not including the Annual Qualified Capacity associated with the Deactivation Notification is calculated as the product of (a) the Lead Market Participant's total Annual Qualified Capacity not including the Annual Qualified Capacity associated with the Deactivation Notification that is the subject of the review and (b) the Internal Market Monitor-simulated Capacity Clearing Price not including the Annual Qualified Capacity associated with the Deactivation Notification.

v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total Annual Qualified Capacity including the Annual Qualified Capacity associated with the Deactivation Notification is calculated as the product of (a) the Lead Market Participant's total Annual Qualified Capacity including the Annual Qualified Capacity associated with the Deactivation Notification that is the subject of the review and (b) the Internal Market Monitor-simulated Capacity Clearing Price including the Annual Qualified Capacity associated with the Deactivation Notification.

vi. For purposes of subsections iv. and v. above, the Internal Market Monitor-simulated Capacity Clearing Price, not to exceed the Capacity Auction Offer Price Cap, is based on the System-Wide Capacity Demand Curve, Capacity Zone Demand Curves as specified in Section III.15.1, and the supply curve developed from the most recent Annual Capacity Auction.

For purposes of the test performed in this Section III.A.24, the Annual Qualified Capacity of a Lead Market Participant includes the capacity of Capacity Resources that are controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the Annual Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Annual Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.24.6 and all capacity the control of which it has contracted to a third party.

III.A.24.7. Proxy Capacity Offer.

For those deactivations the Internal Market Monitor determines have failed both the conduct test set forth in Section III.A.24.5 and the portfolio benefit test set forth in Section III.A.24.6, the first-year break-even price calculated based on the Internal Market Monitor's reasonable expectations regarding net present value of the resource's expected cash flows, the resource's Capacity Performance Payments, and the resource's opportunity costs, determined in accordance with Section III.A.24.3, shall be used as that resource's Proxy Capacity Offer price. The deactivation determination filing made to the Commission as described in Section III.A.24.9 shall include an explanation of the resource's Proxy Capacity Offer price. Unless the Commission determines otherwise, the ISO shall enter Proxy Capacity Offers into the Capacity Auction pursuant to Section III.15.4.

III.A.24.8. Deactivation Determination Notification.

No later than 90 days after the Deactivation Notification Deadline, the Internal Market Monitor shall provide written notification to the Lead Market Participant that submitted each Deactivation Notification concerning the result of the Internal Market Monitor's conduct test conducted pursuant to Section III.A.24.5.

III.A.24.9. Deactivation Determinations Filing.

No later than 120 days after the Deactivation Notification Deadline, the ISO shall make a filing with the Commission pursuant to Section 205 of the Federal Power Act confidentially describing the determinations made by the Internal Market Monitor with respect to each Deactivation Notification failing the conduct test, including the supporting documentation for each such determination. The filing shall identify to the extent possible the components of the Deactivation Notification which were accepted as justified, and shall also identify to the extent possible the components of the Deactivation Notification which were not justified and which resulted in the Internal Market Monitor identifying the resource as requiring a Proxy Capacity Offer. The deactivation determinations filing shall identify the Proxy Capacity Offer price that, pursuant to Section III.15.4, will be entered into the Annual Capacity Auction on behalf of the Lead Market Participant during the Capacity Commitment Period in question if the Commission accepts the deactivation determinations filing. In the event that no Deactivation Notification failed the conduct test associated with a particular Deactivation Notification Deadline, the filing shall state that outcome.

In the event that a Lead Market Participant elects pursuant to Section II.53 to delay a resource's deactivation for reliability reasons, and elects pursuant to Section II.54.1 to be compensated based on net going forward costs, the deactivation determinations filing shall include a description of the resource's net going forward costs and all supporting materials necessary to arrive at the resource's net going forward costs, including a description of any instances in which the Internal Market Monitor-determined net going forward costs differ from the net going forward costs that may be arrived at based solely on the resource's cost workbook submission.

SECTION III
MARKET RULE 1

APPENDIX F
NET COMMITMENT PERIOD COMPENSATION ACCOUNTING

APPENDIX F

NCPC ACCOUNTING

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NCPC ACCOUNTING

III.F.1. General.

For purposes of NCPC calculations:

a. Effective Offers. An Effective Offer for a Resource is (1) the Supply Offer, Demand Reduction Offer, or Demand Bid used in making the decision to commit the Resource, (2) the Supply Offer, Demand Reduction Offer, or Demand Bid used in making the decision to dispatch the Resource at a Desired Dispatch Point above its Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit, and (3) the Day-Ahead Ancillary Services Offer is subject to the following conditions:

i. The Effective Offer used in making the decision to commit the Resource establishes the parameters used for NCPC calculations, including the quantity and price pairs for output, demand reduction, or consumption up to the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit; the Start-Up Fee, No-Load Fee, or Interruption Cost; and the operating limits.

ii. In the event the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit is increased after the decision to commit the Resource, the energy price parameter for output, demand reduction, or consumption at the Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit used in making the decision to commit the Resource will be applied as the energy price parameter for additional output, demand reduction, or consumption up to the increased Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit.

iii. In the event a Minimum Generation Emergency is declared, the Economic Minimum Limit will be replaced with the Emergency Minimum Limit for purposes of determining the energy price parameter of the Effective Offer.

iv. The Effective Offer takes account of any mitigation applied to the Supply Offer and the Day-Ahead Ancillary Services Offer, whether performed prior to or after the commitment or dispatch decision is made.

v. The Effective Offer takes account of a reduction in the energy price parameter, the Start-Up Fee, the No-Load Fee, or the Interruption Cost in a Supply Offer or Demand Reduction Offer; or an increase in the energy price parameter of a Demand Bid that is made prior to the end of the Resource's Commitment Period.

vi. In the event the ISO approves the Resource's synchronization to the system as a Pool-Scheduled Resource earlier than its scheduled time, the Effective Offer takes account of the lesser of the energy price parameter, the Start-Up Fee and the No-Load Fee in place for the scheduled Commitment Period or the actual early release-for-dispatch time.

vii. A Resource that is online providing synchronous condensing is considered to be in a hot temperature state for the purpose of determining the Start-Up Fee for the Effective Offer when the Resource is requested to switch from synchronous condensing to provide energy.

viii. The Effective Offer takes account of cost verification performed under Sections III.1.8.1 and III.1.9.1.

ix. The energy price parameter of the Effective Offer for a Demand Response Resource is the energy price parameter submitted in the Demand Reduction Offer, even where the Demand Reduction Threshold Price is used to clear the market pursuant to Section III.1.10.1A(e)(ii).

b. Treatment of Self-Schedules.

i. In the Day-Ahead Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to the minimum of the Energy Offer Floor and the Day-Ahead Locational Marginal Price; or, in the case of a Storage DARD, is treated as having a Demand Bid with an energy price parameter for consumption up to its Minimum Consumption Limit equal to the maximum of the Demand Bid Cap and the Day-Ahead Locational Marginal Price. Any amounts (MW) offered or bid above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid.

ii. In the Real-Time Energy Market, a Resource that is committed as a Self-Schedule is treated either: (i) as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to $0/MWh; or (ii) as having a Demand Bid for consumption up to the Minimum Consumption Limit at the Demand Bid Cap. Any amounts (MW) offered above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid. For any hour for which a Resource is dispatched pursuant to Section III.1.10.9(f), the Resource is treated either: (i) as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the requested amount at the Energy Offer

Floor; or (ii) as having a Demand Bid with an energy price parameter for consumption up to the requested amount at the Demand Bid Cap.

iii. If the Resource's Supply Offer contains a Self-Schedule for fewer contiguous hours than its Minimum Run Time, the minimum number of additional hours required to satisfy the Resource's Minimum Run Time will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market. If the Resource is committed for one or more hours immediately prior to and contiguous with the Self-Schedule, the hours of that prior Commitment Period will be counted toward satisfying the Resource's Minimum Run Time before hours subsequent to the Self-Schedule are counted. If the Resource's Supply Offer contains two Self-Schedules separated by less than the Resource's Minimum Down Time, the hours between the two Self-Schedules will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market.

c. Sub-Hourly Intervals. If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

d. Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Minimum Run Time or Minimum Reduction Time Carries Into Second Operating Day. If a Resource that is committed in either (i) the Day-Ahead Energy Market, or (ii) the Reserve Adequacy Analysis prior to the start of the Operating Day must continue to operate across an Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for hour ending 24 of the Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day. If a Resource that is committed during the Operating Day must continue to operate across the Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the second Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day.

e. Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Committed Prior to Day-Ahead Energy Market. If a Resource is committed for an Operating Day prior to the Day-Ahead Energy Market, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the Operating Day at the time of the commitment is used to establish the Effective Offer for the period of the commitment.

f. Eligibility for NCPC Credits When Performing Audits or Facility and Equipment Testing. The Real-Time NCPC Credit calculation for a Resource performing an audit uses the Start-Up Fee, No-Load Fee, Interruption Cost, Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction in the Effective Offer applicable to the Commitment Period during which the audit is conducted, and does not take account of any increases to the Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction that take place in the course of the audit.

Market Participants are not eligible for NCPC Credits when conducting audits or Facility and Equipment Testing under the following conditions:

i. When a Market Participant requests that some hours of the commitment of a Pool-Scheduled Resource be used to satisfy an audit, and the Market Participant has changed the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit for those hours for the purpose of conducting the audit, the Market Participant is not eligible for Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the audit is conducted.

ii. When a Market Participant Self-Schedules a Resource to perform the audit, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the Self-Schedule and is not eligible for Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the audit is conducted.

iii. When a Market Participant requests that an audit be performed that requires the ISO to dispatch the Resource for the audit without advance notice to the Market Participant, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment or Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the audit is conducted.

iv. When an ISO-Initiated Claimed Capability Audit is performed pursuant to III.1.5.1.4, the Market Participant is not eligible for Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the audit is conducted if both of the following are true:

1. the Resource had a summer or winter Seasonal Claimed Capability or Seasonal DR Audit value equal to 0 MW at the beginning of the current Capability Demonstration Year, and

2. the ISO Initiated Claimed Capability Audit is the first Claimed Capability Audit that the Resource performs during that Capability Demonstration Year.

v. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Pool-Scheduled Resource, the Economic Minimum Limit (or Minimum Consumption Limit for a Binary Storage DARD) in place at the time of the commitment decision is used for calculating Real-Time Commitment NCPC Credits and the Market Participant is not eligible for Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.

vi. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Resource that Self-Scheduled, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment and is not eligible for Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, or Rapid Response Pricing Opportunity Cost NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.

g. Coordinated External Transactions are Not Eligible for NCPC and are excluded from NCPC Charges. Notwithstanding anything to the contrary in this Appendix F, Market Participants are not eligible to receive NCPC Credits for Coordinated External Transactions purchases or sales and shall be excluded from all NCPC Charge calculations under this Appendix F.

h. Demand Response Resource Credit Calculations. Where indicated in Section III.F.2, the costs and revenues for a Demand Response Resource, other than those associated with Net Supply or Interruption Costs, are increased by average avoided peak distribution losses.

i. Following Dispatch Instructions.

i. For the purpose of allocating NCPC costs, a Resource with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit greater 50 MW is considered to be following a dispatch instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 10% above its Desired Dispatch Point and not less than 10% below its Desired Dispatch Point for each interval in the hour. A Resource with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit less than or equal to 50 MW is considered to be following a Dispatch Instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 5 MW above its Desired Dispatch Point and is not less than 5 MW below its Desired Dispatch Point for each interval in the hour. If the Resource violates this criterion in any interval during the hour, the Resource is considered to be not following Dispatch Instructions for the entire hour.

ii. DNE Dispatchable Generators are considered to be following Dispatch Instructions if the actual output of the DNE Dispatchable Generator is at or below its Do Not Exceed Dispatch Point.

III.F.2. NCPC Credits

III.F.2.1 Day-Ahead Market NCPC Credits

III.F.2.1.1. Eligibility for Credit. A Generator Asset with a Supply Offer, a Demand Response Resource with a Demand Reduction Offer, or a Storage DARD with a Demand Bid that clears the Day-Ahead Energy Market in an hour is eligible for Day-Ahead Market NCPC Credits for the hour.

III.F.2.1.2. Settlement Period. For a Generator Asset, a Demand Response Resource, or a Storage DARD, for purposes of calculating Day-Ahead Market NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day for which a Resource has cleared in the Day-Ahead Energy Market. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator or to or from a Fast Start Demand Response Resource, or any time a DNE Dispatchable Generator's operating characteristics change to or from a Flexible DNE Dispatchable Generator, and the Resource is committed with the changed designation.

III.F.2.1.3. Eligible Quantity. For a Generator Asset, Demand Response Resource, or Storage DARD, the eligible quantity of energy is the amount of energy the Resource clears in the Day-Ahead Energy Market for each hour of the settlement period.

III.F.2.1.3A Hourly Bid. For a Storage DARD, the hourly bid is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each hour of the settlement period.

III.F.2.1.4 Hourly Cost for Energy.

(a) For a Generator Asset, the hourly cost is equal to the energy price parameter for the eligible quantity, the Start-Up Fee and the No-Load Fee as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2.

(b) For a Demand Response Resource, the hourly cost is equal to the energy price parameter for the eligible quantity and the Interruption Cost as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2.

(c) For a Storage DARD, the hourly cost is equal to the Day-Ahead Locational Marginal Price for each hour of the settlement period multiplied by the eligible quantity.

III.F.2.1.4.1 For a Generator Asset or a Demand Response Resource, the Start-Up Fee or Interruption Cost is apportioned equally over the hours from the time the Resource is scheduled to begin its commitment through the end of the Commitment Period during which the Minimum Run Time or Minimum Reduction Time is scheduled to expire.

III.F.2.1.4.2 For a Generator Asset or a Demand Response Resource, when the period of hours over which the Start-Up Fee or Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee or Interruption Cost.

III.F.2.1.4.A Hourly Cost for Day-Ahead Ancillary Services. The hourly cost for Day-Ahead Ancillary Services is equal to the Day-Ahead Ancillary Services Offer prices as reflected in the Effective Offer multiplied by the amount of each award for each hour of the settlement period.

III.F.2.1.5 Hourly Revenue for Energy. For a Generator Asset or a Demand Response Resource, the hourly revenue is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity for the Resource, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price.

III.F.2.1.5.A Hourly Revenue for Day-Ahead Ancillary Services. For a Generator Asset, a Demand Response Resource, or a DARD, the Day-Ahead Ancillary Services hourly revenue is equal to the total Day-Ahead Ancillary Services Market Credit as calculated in Section III.3.2.1(q)(1) for each hour of the settlement period.

III.F.2.1.6 General Credit Calculation. Except as provided in Section III.F.2.1.7 below, the Day-Ahead Market NCPC Credit for a Resource, adjusted as described in III.F.1(h), is equal to:

(a) For a Generator Asset or a Demand Response Resource: the greater of (i) zero, and; (ii) the total hourly cost for Energy and Day-Ahead Ancillary Services for the Resource in all hours of the settlement period, minus the total hourly revenue for Energy and Day-Ahead Ancillary Services for the Resource in all hours of the settlement period, where the costs and revenues of a Demand Response Resource, other than those associated with Interruption Costs, are increased by average avoided peak distribution losses; and

(b) For a Binary Storage DARD: the greater of (i) zero and (ii) the total hourly cost for Energy and Day-Ahead Ancillary Services for the Resource in all hours of the settlement period, minus the total hourly bids in all hours of the settlement period and the total Day-Ahead Ancillary Services hourly revenue.

III.F.2.1.7 Credit Calculation for Fast Start Generators, Flexible DNE Dispatchable Generators, Fast Start Demand Response Resources and Binary Storage DARDs Based on Daily Starts, and for Continuous Storage Generator Assets and Continuous Storage DARDs. If either (1) the number of daily starts for a Fast Start Generator, Flexible DNE Dispatchable Generator, Fast Start Demand Response Resource or Binary Storage DARD is less than the resource's Maximum Number of Daily Starts, or (2) the resource is a Continuous Storage Generator Asset or a Continuous Storage DARD, then the resource's Day-Ahead Market NCPC Credit, adjusted as described in III.F.1(h), is calculated as follows:

(a) For a Fast Start Generator, a Continuous Storage Generator Asset, a Flexible DNE Dispatchable Generator or a Fast Start Demand Response Resource, the Day-Ahead Market NCPC Credit is equal to, for each hour of the settlement period, the greater of (i) zero, and; (ii) the hourly cost for Energy and Day-Ahead Ancillary Services for the Resource in an hour, minus the hourly revenue for Energy and Day-Ahead Ancillary Services for the Resource in that hour.

(b) For a Storage DARD, the Day-Ahead Market NCPC Credit is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the total hourly cost for Energy and Day-Ahead Ancillary Services for the Resource in an hour, minus the total hourly bid for the Resource in that hour and the total Day-Ahead Ancillary Services hourly revenue.

III.F.2.2 Real-Time Energy Market NCPC Credits. Real-Time Energy Market NCPC Credits include a Real-Time Commitment NCPC Credit, a Real-Time Dispatch NCPC Credit and a Real-Time Dispatch Lost Opportunity Cost NCPC Credit. For purposes of this Section III.F.2.2, unless otherwise expressly stated, costs and revenues shall be calculated at a five-minute interval.

III.F.2.2.1 Eligibility for Credit.

(a) Commitment Credits – The following Resources are eligible for Real-Time Commitment NCPC Credits for some or all intervals of the hour: (i) a Generator Asset with a Supply Offer that has been submitted in the Real-Time Energy Market and that has been committed by the ISO; (ii) a Demand Response Resource with a Demand Reduction Offer that has been submitted in the Real-Time Energy Market; or (iii) a Binary Storage DARD with a Demand Bid that has been submitted in the Real-Time Energy Market and that has been committed by the ISO.

(b) Dispatch Credits – The following Resources are eligible for Real-Time Dispatch NCPC Credits for some or all intervals of the hour: (i) a Generator Asset with a Supply Offer that has been submitted in the Real-Time Energy Market; (ii) a Demand Response Resource with a Demand Reduction Offer that has been submitted in the Real-Time Energy Market; (iii) a Storage DARD with a Demand Bid that has been submitted in the Real-Time Energy Market; or (iv) a Storage DARD that has been Postured to increase its consumption. The Real-Time Dispatch NCPC Credit shall be zero, however, if the Generator Asset has provided Regulation during the interval.

(c) Dispatch Lost Opportunity Cost Credits – A Generator Asset with a Supply Offer, a Demand Response Resource with a Demand Reduction Offer, or a Dispatchable Asset Related Demand with a Demand Bid that is committed and able to respond to Dispatch Instructions during the interval is eligible to receive a Real-Time Dispatch Lost Opportunity Cost NCPC Credit; provided, however, that such credit shall be zero if the Generator Asset, Demand Response Resource, or Dispatchable Asset Related Demand has been Postured or has provided Regulation during the interval.

III.F.2.2.2 Real-Time Commitment NCPC Credits

III.F.2.2.2.1. Settlement Period.

(a) For Generator Assets, Demand Response Resources, and Binary Storage DARDs, for purposes of calculating Real-Time Commitment NCPC Credits, a settlement period is a period of one or more contiguous intervals in an Operating Day during which a Resource is operating pursuant to one or more commitments in the Day-Ahead Energy Market or Real-Time Energy Market.

(b) For Generator Assets and Demand Response Resources, a new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, to or from a Flexible DNE Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.

(c) For Generator Assets and Binary Storage DARDs, in the event of an interruption in operation of a Resource, operation will be considered contiguous if the Resource returns to operation in accordance with the original commitment issued prior to the interruption.

III.F.2.2.2.2. Eligible Quantity.

III.F.2.2.2.2.A For a Binary Storage DARD, the eligible quantity for each interval is the amount of energy equal to the lesser of its Economic Dispatch Point for that interval and its Metered Quantity For Settlement for the interval.

III.F.2.2.2.2.1.

(a) For a Generator Asset, the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy equal to the lesser of the Resource's Metered Quantity For Settlement and Economic Dispatch Point for the interval; provided however, that during contiguous pricing intervals in which the Generator Asset's Economic Dispatch Point is higher than it would otherwise be as a result of an offered ramp rate limitation, then the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy for the interval equal to the lesser of: (a) the Generator Asset's Metered Quantity For Settlement; and (b) the greater of: (i) the Generator Asset's expected output level had it reduced its output per its offered ramp rate during the relevant intervals as instructed by the ISO, and (ii) the output level to which the Generator Asset would have been dispatched absent the offered ramp rate limitation.

(b) For a Generator Asset, the eligible quantity for determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit is the lesser of the Resource's Metered Quantity For Settlement and Economic Dispatch Point for the interval, except that Metered Quantity For Settlement is used as the eligible quantity (i) when the Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) when the Resource is ramping from an offline state to be released for dispatch or (iii) after the Resource has been released for shutdown.

III.F.2.2.2.2.2.

(a) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the lesser of the Resource's Metered Quantity For Settlement and its Economic Dispatch Point for the interval; provided however, that during contiguous pricing intervals in which the Demand Response Resource's Economic Dispatch Point is higher than it would otherwise be as a result of an offered ramp rate limitation, then the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy for the interval equal to the lesser of: (a) the Demand Response Resource's Metered Quantity For Settlement; and (b) the greater of: (i) the Demand Response Resource's expected demand reduction had it provided the reduction per its offered ramp rate during the relevant intervals as instructed by the ISO, and (ii) the demand reduction level at which the Demand Response Resource would have been dispatched absent the offered ramp rate limitation.

(b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit is equal to the eligible quantity used to determine interval costs pursuant to (a) above, except that the eligible quantity shall be the Metered Quantity For Settlement if any of the following are true: (i) the Demand Response Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) the Demand Response Resource Notification Time and Demand Response Resource Start-Up Time have not concluded, or (iii) the Demand Response Resource has received an instruction to stop reducing demand.

III.F.2.2.2.3. Interval Cost.

(a) The interval cost for a Generator Asset is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Start-Up Fee and No-Load Fee as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1, III.F.2.2.2.3.2, and III.F.2.2.2.3.3.

(b) The interval cost for a Demand Response Resource is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Interruption Cost as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1 and III.F.2.2.2.3.2, provided that costs shall be set to $0 for the interval when there is a negative demand reduction.

(c) The interval cost for a Binary Storage DARD is the Real-Time Price for the interval multiplied by the eligible quantity. The interval cost is reduced by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval cost is also reduced by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5.

III.F.2.2.2.3.1

(a) For a Generator Asset, the energy cost for an interval excludes the cost of (a) energy produced when the Resource is ramping from an offline state to be released for dispatch and (b) energy produced after the Resource has been released for shutdown.

(b) For a Demand Response Resource, the energy cost for an interval excludes the cost of (a) energy produced prior to the conclusion of the Demand Response Resource Start-Up Time and (b) energy produced after the Demand Response Resource has received an instruction to stop reducing demand.

III.F.2.2.2.3.2

(a) For a Generator Asset, the Start-Up Fee is apportioned equally over the intervals from the time the Generator Asset is released for dispatch through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire, subject to the following conditions:

  (i) The Start-Up Fee is reduced in proportion to the number of minutes after 30 the Generator Asset is released for dispatch (measured from the time the Generator Asset was scheduled to be released for dispatch), divided by the time from when the Generator Asset was scheduled to be released for dispatch through the end of the Commitment Period during which the Minimum Run Time was scheduled to expire.

  (ii) The Start-Up Fee is excluded from the interval cost calculation if the Generator Asset is synchronized to the system prior to its scheduled synchronization time without the ISO's approval of the Generator Asset's synchronization as a Pool-Scheduled Resource.

  (iii) The portion of the Start-Up Fee apportioned to any interval during which the Generator Asset is not online because the Generator Asset has tripped is excluded from the interval cost calculation, except in the event the Generator Asset is not online due to a trip that results from equipment failure involving equipment located on the electric network beyond the low voltage terminals of the Generator Asset's step-up transformer. It is the responsibility of the Lead Market Participant for the Generator Asset to inform the ISO at xtrip@iso-ne.com within 30 days that the trip was the result of such a transmission-related event.

(iv) The Start-Up Fee is not reduced when the Generator Asset has shutdown with the ISO's approval prior to the end of its Commitment Period.

(v) The additional Start-Up Fee for a Generator Asset requested to re-start following a trip is apportioned equally over the remaining intervals of the Commitment Period when the ISO requests a Generator Asset to re-start to complete its Commitment Period.

(vi) When the period of intervals over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.

(b) For a Demand Response Resource, the Interruption Cost is apportioned equally over the intervals from the time the Demand Response Resource Start-Up Time concludes through the end of the Commitment Period during which the Minimum Reduction Time is scheduled to expire, subject to the following conditions:

(i) The Interruption Cost is reduced in proportion to the number of minutes after 30 the Demand Response Resource begins to provide a demand reduction (measured from the conclusion of the Demand Response Resource Start-Up Time), divided by the time from the conclusion of the Demand Response Resource Start-Up Time through the end of the Commitment Period during which the Minimum Reduction Time was scheduled to expire.

(ii) The portion of the Interruption Cost apportioned to any interval during which the Demand Response Resource is not providing a demand reduction because the Demand Response Resource has become unavailable to provide a reduction is excluded from the interval cost calculation.

(iii) The Interruption Cost is not reduced when the Demand Response Resource has stopped reducing demand with the ISO's approval prior to the end of its Commitment Period. When the period of intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.

(iv) When the period of intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.

III.F.2.2.2.3.3. For a Generator Asset for each hour, the No-Load Fee is equally apportioned to each interval in the hour during the period when the Generator Asset is online following its release for dispatch and prior to its release for shutdown. The No-Load Fee is pro-rated for the hour during which the Generator Asset is released for dispatch, the hour during which the Generator Asset is released for shutdown, and any other hour during which the Generator Asset operates for less than 60 minutes.

III.F.2.2.2.3.A Interval Bid. The interval bid for a Binary Storage DARD is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each interval of the settlement period.

III.F.2.2.2.4 Interval Revenue. The interval revenue for a Generator Asset or Demand Response Resource is equal to the Real-Time Price for each interval of the settlement period multiplied by the eligible quantity for the interval. The revenue for an interval is increased by the amount by which the interval revenues in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.4 exceed the interval costs in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.3. The interval revenue is increased by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval revenue is also increased by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5. The revenues when the Generator Asset is ramping from an offline state to be released for dispatch, or during the Demand Response Resource Start-Up Time, are apportioned equally to the intervals of the Minimum Run Time or Minimum Reduction Time.

III.F.2.2.2.4.1. For a Generator Asset, revenues for output up to the Resource's Economic Minimum Limit in a Self-Scheduled interval, calculated as the Real-Time Price multiplied by the output, are excluded from the revenue for the Real-Time Commitment NCPC Credit calculation.

III.F.2.2.2.4.2. For a Demand Response Resource, revenues shall be set to $0 for the interval when the Locational Marginal Price is positive and there is a negative demand reduction.

III.F.2.2.2.5 Credit Calculation for Generator Assets and Demand Response Resources. The Real-Time Commitment NCPC Credit for a Generator Asset or a Demand Response Resource, adjusted as described in III.F.1(h) is equal to:

(a) For the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval revenue for the Resource for the period,

plus,

(b) For each remaining interval of the settlement period following the completion of the Minimum Run Time or Minimum Reduction Time, the greater of ((i) zero, and; (ii) the maximum potential net revenues for the Resource in the period) minus the actual net revenues for the Resource in the period, where

  (i) The maximum potential net revenue is the maximum accumulated net interval revenue for operating and then shutting down (or, for a Demand Response Resource, reducing demand and then ceasing to reduce demand) during the period.

  (ii) The actual net revenue is the accumulated net interval revenue over the period.

  (iii) The net interval revenue is the interval revenues minus interval costs in the period.

III.F.2.2.2.6. [Reserved.]

III.F.2.2.2.7 Credit Calculation for Binary Storage DARDs. The Real-Time Commitment NCPC Credit for a Binary Storage DARD is equal to:

(a) For the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval bid for the Resource for the period,

plus,

(b) For each remaining interval of the settlement period following the completion of the Minimum Run Time, the greater of ((i) zero, and; (ii) the maximum potential net benefit for the Resource in the period) minus the actual net benefit for the Resource in the period, where

  (i) The maximum potential net benefit is the maximum accumulated net interval benefit for operating and then shutting down during the period.

  (ii) The actual net benefit is the accumulated net interval benefit over the period.

  (iii) The net interval benefit is the interval bid minus interval cost in the period.

III.F.2.2.2.8 Resources with Commitment in the Day-Ahead Energy Market (other than Fast Start Generators, Fast Start Demand Response Resources, and Binary Storage DARDs).

(a) For purposes of calculating the interval cost under Section III.F.2.2.2.3, for any hour in which a Resource (other than a Fast Start Generator, Fast Start Demand Response Resource, or Binary Storage DARD) has a commitment in the Day-Ahead Energy Market, the Start-Up Fee, No-Load Fee, Interruption Cost and energy price parameter for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to $0 for the hour. The Start-Up Fee shall not be set to $0 in the case when a Resource re-starts at ISO request following a trip.

(b) For purposes of calculating the interval revenue under Section III.F.2.2.2.4, for any hour in which a Resource (other than a Fast Start Generator, Fast Start Demand Response Resource, or Binary Storage DARD) has a commitment in the Day-Ahead Energy Market, the revenue for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to $0 for the hour if such revenue is less than $0.

(c) Notwithstanding anything to the contrary in this Section III.F.2.2.2, a Generator Asset that cleared in the Day-Ahead Energy Market and performs an audit scheduled by the ISO pursuant to Section III.1.5.2(f) during all or part of its Day-Ahead schedule on a higher-priced fuel than that which formed the basis of the Generator Asset's Supply Offer in the Day-Ahead Energy Market shall receive additional compensation equal to:

i. For the MW quantity equal to the lesser of the Generator Asset's actual metered output and Economic Dispatch Point, the difference between 1) the incremental energy audit costs based on the Supply Offer using the fuel on which the audit was performed and 2) amounts calculated for that same operation as reflected in the greater of the Day-Ahead Supply Offer and the cost-based Reference Levels calculated using the fuel on which the Day-Ahead Supply Offer was based; and

ii. The difference between the No-Load Fee based on the Supply Offer using the fuel on which the audit was performed and the No-Load Fee for that same operation as reflected in the Day-Ahead Supply Offer; and

iii. Any additional Start-Up Fees incurred as a result of performing the audit.

III.F.2.2.3. Real-Time Dispatch NCPC Credits for Generator Assets and Demand Response Resources.

III.F.2.2.3.1 Settlement Period.

(a) Except as provided in Section III.F.2.2.3.1(b), for Generator Assets and Demand Response Resources, for purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement for a Resource are each greater than its Economic Dispatch Point, excluding any period of time when:

i. For a Generator Asset, the generator is ramping from an offline state to be released for dispatch, and after the generator has been released for shutdown, or

ii. For a Demand Response Resource, prior to the conclusion of the Demand Response Start-Up Time and after the Demand Response Resource has received a Dispatch Instruction to stop reducing demand.

(b) For a Continuous Storage Generator Asset associated with an ATRR that has provided Regulation during the interval, a settlement period is an interval when the Desired Dispatch Point is greater than the Economic Dispatch Point.

III.F.2.2.3.2. Eligible Quantity.

III.F.2.2.3.2.1.

(a) For a Generator Asset, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit is the Generator Asset's Economic Dispatch Point for the interval subtracted from the lesser of the Generator Asset's Metered Quantity For Settlement or Desired Dispatch Point for the interval, unless a Continuous Storage Generator Asset is associated with an ATRR that has provided Regulation during the interval, in which case the eligible quantity is the Generator Asset's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.

(b) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit is the Demand Response Resource's Economic Dispatch Point for the interval subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement and its Desired Dispatch Point for the interval.

III.F.2.2.3.2.2.

(a) For a Generator Asset, the eligible quantity for determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit is the Generator Asset's Metered Quantity For Settlement for the interval minus the Generator Asset's Economic Dispatch Point, except that the Generator Asset's Economic Dispatch Point subtracted from the lesser of the Generator Asset's Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval. Notwithstanding the foregoing, if a Continuous Storage Generator Asset is associated with an ATRR that has provided Regulation during the interval, the eligible quantity is the Generator Asset's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.

(b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit equals the Demand Response Resource's Metered Quantity For Settlement for the interval minus the Demand Response Resource's Economic Dispatch Point, except that the Demand Response Resource's Economic Dispatch Point subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval.

III.F.2.2.3.3 Interval Cost. For a Generator Asset or a Demand Response Resource, the interval cost is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer and does not include the Start-Up Fee, the No-Load Fee, or the Interruption Cost.

III.F.2.2.3.4 Interval Revenue. For a Generator Asset or a Demand Response Resource, the interval revenue is equal to the Real-Time Price multiplied by the eligible quantity.

III.F.2.2.3.5. Credit Calculation. For a Generator Asset or a Demand Response Resource, the Real-Time Dispatch NCPC Credit in an interval is equal to the greater of (i) zero and (ii) the interval cost minus the interval revenue for the Resource, adjusted as described in III.F.1(h).

III.F.2.2.4 Real-Time Dispatch NCPC Credits for Storage DARDs

III.F.2.2.4.1 Settlement Period. For purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement are each greater than the Storage DARD's Economic Dispatch Point, unless a Continuous Storage DARD is associated with an ATRR that has provided Regulation during the interval, in which case a settlement period is an interval when the Desired Dispatch Point is greater than the Economic Dispatch Point.

III.F.2.2.4.2 Eligible Quantity. The eligible quantity of energy is equal to the greater of (i) zero and (ii) the Storage DARD's Economic Dispatch Point for the interval subtracted from the lesser of the Storage DARD's Metered Quantity For Settlement or Desired Dispatch Point for the interval, unless a Continuous Storage DARD is associated with an ATRR that has provided Regulation during the interval, in which case the eligible quantity is the DARD's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.

III.F.2.2.4.3 Interval Cost. The interval cost is the Real-Time Price for the interval multiplied by the eligible quantity.

III.F.2.2.4.4 Interval Bid. The interval bid is equal to the energy price parameter for the eligible quantity as reflected in the Demand Bid for each interval of the settlement period.

III.F.2.2.4.5 Credit Calculation. The Real-Time Dispatch NCPC Credit for an eligible Storage DARD in an interval is equal to the greater of: (i) zero, and; (ii) the interval cost minus the interval bid in that interval.

III.F.2.2.5. Real-Time Dispatch Lost Opportunity Cost NCPC Credits

III.F.2.2.5.1. Maximum Net Revenue or Maximum Net Benefit.

(a) For a Generator Asset or a Demand Response Resource, the maximum net revenue during the interval is the Resource's energy revenue at the Economic Dispatch Point, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point, as described in III.F.1(h).

(b) For a Dispatchable Asset Related Demand, the maximum net benefit during the interval is the Resource's energy price parameter for the Economic Dispatch Point as reflected in the Demand Bid, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point.

III.F.2.2.5.2. Actual Net Revenue or Actual Net Benefit.

(a) The actual net revenue for a Generator Asset or Demand Response Resource shall be the sum, adjusted as described in III.F.1(h), of the following two values:

   (i) for a Continuous Storage Generator Asset associated with an ATRR that has provided Regulation during the interval, the energy revenue at the dispatched energy quantity minus the offered energy cost for that quantity; otherwise, the greater of: (1) the energy revenue at the Metered Quantity For Settlement minus the offered energy cost for that quantity and (2) the energy revenue at the dispatched energy quantity minus the offered energy cost for that quantity; and

   (ii) the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.

(b) The actual net benefit for a Dispatchable Asset Related Demand shall be the sum of the following two values:

   (i) for a Continuous Storage DARD associated with an ATRR that has provided Regulation during the interval, the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid minus the offered energy cost for that quantity; otherwise, the greater of: (1) the energy price parameter for the Metered Quantity For Settlement as reflected in the Demand Bid minus the offered energy cost for that quantity and (2) the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid minus the offered energy cost for that quantity; and

(ii) the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.

III.F.2.2.5.3. Credit Calculation. For a Generator Asset, a Demand Response Resource, or a Dispatchable Asset Related Demand, the Real-Time Dispatch Lost Opportunity Cost NCPC Credit is equal to the greater of: (i) zero; and (ii) the Resource's maximum net revenue or benefit for the interval less its actual net revenue or benefit for the interval.

The Dispatch Lost Opportunity Cost NCPC Credit for a Resource for an interval shall be reduced by the amount of any Rapid Response Pricing Opportunity Cost NCPC Credits for which the Resource is eligible for that interval, but shall be no less than zero.

III.F.2.3. Special Case NCPC Credit Calculations

III.F.2.3.1. Day-Ahead External Transaction Import and Increment Offer NCPC Credits

III.F.2.3.1.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction imports or Increment Offers at an External Node are eligible for Day-Ahead External Transaction Import and Increment Offer NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.1.2. Hourly Offer. The Day-Ahead offer for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the offer price.

III.F.2.3.1.3. Hourly Revenue. The Day-Ahead revenue for a pool-scheduled External Transaction import at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, not subject to the credit conditions specified in Section III.3.2.1(q)(4)(ii). For Increment Offers at an External Node, the Day-Ahead revenue at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Locational Marginal Price.

III.F.2.3.1.4. Credit Calculation. A Day-Ahead External Transaction Import and Increment Offer NCPC Credit for an External Transaction import or Increment Offer, for an hour, is equal to any portion of the Day-Ahead offer in excess of the Day-Ahead revenue for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction import or Increment Offer for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction export or Decrement Bid for the same External Node and hour, the Day-Ahead External Transaction Import and Increment Offer NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction import or Increment Offer at the External Node for the hour that is not offset by the amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour. If multiple External Transaction imports or Increment Offers at an External Node are eligible for a Day-Ahead External Transaction Import and Increment Offer NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction imports and Increment Offers will be offset in order from the highest to the lowest-priced transactions or offers.

III.F.2.3.2. Day-Ahead External Transaction Export and Decrement Bid NCPC Credits

III.F.2.3.2.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction exports or Decrement Bids at an External Node are eligible for Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.2.2. Hourly Bid. The Day-Ahead bid for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the bid price.

III.F.2.3.2.3. Hourly Cost. The Day-Ahead cost for a pool-scheduled External Transaction export at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price at the External Node, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price. For Decrement Bids at an

External Node, the Day-Ahead cost at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Locational Marginal Price.

III.F.2.3.2.4. Credit Calculation. A Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for an External Transaction export or Decrement Bid, for an hour, is equal to any portion of the Day-Ahead hourly cost in excess of its Day-Ahead hourly bid for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction export or Decrement Bid for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction import or Increment Offer for the same External Node and hour, the Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour that is not offset by the amount (MW) of the total cleared External Transaction import or Increment Offer at the External Node for the hour. If multiple External Transaction exports or Decrement Bids at an External Node are eligible for a Day-Ahead External Transaction Export and Decrement Bid NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction exports and Decrement Bids will be offset in order from the lowest to the highest-priced transactions or bids.

III.F.2.3.3. Real-Time External Transaction NCPC Credits (Import and Export)

III.F.2.3.3.1. Eligibility for Credit. All Market Participants that submit pool-scheduled External Transactions (import or export) are eligible for Real-Time External Transaction NCPC Credits, with the exception of External Transactions to wheel energy through the New England Control Area.

III.F.2.3.3.2. Eligible Quantity.

(a) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that either (i) did not clear in the Day-Ahead Energy Market, or (ii) cleared in the Day-Ahead Energy Market and the price was subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction.

(b) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that cleared in the Day-Ahead Energy Market and the price was not subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction in excess of the cleared Day-Ahead scheduled transaction amount.

III.F.2.3.3.3. Hourly Offer. The hourly offer for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval offer, which is calculated by multiplying the eligible quantity by the offer price for the interval.

III.F.2.3.3.4. Hourly Revenue. The hourly revenue for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval revenue, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

III.F.2.3.3.5. Hourly Bid. The hourly bid for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval bid, which is calculated by multiplying the eligible quantity by the bid price for the interval.

III.F.2.3.3.6. Hourly Cost. The Real-Time cost for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval cost, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

III.F.2.3.3.7. Credit Calculation. A Real-Time External Transaction NCPC Credit for an External Transaction import for an hour is equal to any portion of the hourly offer in excess of the hourly revenue. A Real-Time External Transaction NCPC Credit for an External Transaction export for an hour is equal to any portion of the hourly cost in excess of the hourly bid.

III.F.2.3.4. [Reserved.]

III.F.2.3.5. Real-Time Synchronous Condensing NCPC Credits

III.F.2.3.5.1. Eligibility for Credit. A Resource that is dispatched as a Synchronous Condenser is eligible for Real-Time Synchronous Condensing NCPC Credits.

III.F.2.3.5.2. Condensing Offer Amount. The condensing offer amount for a Resource is equal to the number of hours that the Resource is dispatched as a Synchronous Condenser in an Operating Day multiplied by the hourly price to condense as specified in the Offer Data for the Resource. For a Resource committed from an offline state to provide synchronous condensing, the condensing offer amount includes the condensing start-up fee as specified in the Offer Data for the Resource. In the event an hourly price to condense or condensing start-up fee is not included in the Offer Data for the Resource for the hours that the Resource is dispatched as a Synchronous Condenser, the value for the parameter will be zero.

III.F.2.3.5.3. Credit Calculation. The Real-Time Synchronous Condensing NCPC Credit for a Resource for an Operating Day is equal to the condensing offer amount for that Operating Day.

III.F.2.3.6. Cancelled Start NCPC Credits

III.F.2.3.6.1. Eligibility for credit. A Pool-Scheduled Generator Asset or Demand Response Resource is eligible for a Cancelled Start NCPC Credit if the ISO cancels its commitment of the Pool-Schedule Resource before a Generator Asset is synchronized to the New England Transmission System, or before a Demand Response Resource has completed its Demand Response Resource Notification Time, except that a Market Participant is not eligible for a credit under the following conditions:

(a) The start is cancelled before the commencement of the Notification Time or the Demand Response Resource Notification Time;

(b) The Resource's Notification Time or Demand Response Resource Notification Time as reflected in the Effective Offer is equal to or greater than 24 hours;

(c) The Generator Asset is synchronized to the New England Transmission System for a Self-Schedule within the period of time equal to the lesser of its Minimum Down Time or 10 hours after receiving the ISO cancelled start order; or

(d) The Generator Asset fails to meet its scheduled synchronization time and the ISO cancelled start order is issued more than two hours after the Resource's scheduled synchronization time.

III.F.2.3.6.2. Credit Calculation. The Cancelled Start NCPC Credit for a Resource is equal to the Start-Up Fee or Interruption Cost reflected in the Effective Offer multiplied by the percentage of the Notification Time or Demand Response Resource Notification Time, as reflected in the Effective Offer, that the Resource completed prior to the ISO cancelled start order, where:

(a) The percentage of Notification Time or Demand Response Notification Time completed is equal to the number of minutes after the start of the Notification Time or Demand Response Notification Time the Resource was cancelled divided by the Notification Time or Demand Response Notification Time, and cannot exceed 100%.

III.F.2.3.7. Hourly Shortfall NCPC Credits

III.F.2.3.7.1. Eligibility for Credit. A Generator Asset, Demand Response Resource, or Binary Storage DARD that is pool-scheduled in the Day-Ahead Energy Market is eligible for Hourly Shortfall NCPC Credits for an hour if the ISO (1) cancels its commitment of a non-Fast Start Generator, a non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator; or (2) does not dispatch a Fast Start Generator, a Fast Start Demand Response Resource, a Binary Storage DARD, or a Flexible DNE Dispatchable Generator for the hour; and (3) either the Generator Asset or Binary Storage DARD is offline and available for operation and the Generator Asset associated with the DARD is not supplying electricity to the grid, or the Demand Response Resource has not been dispatched and is available for operation; except that (4) a Market Participant is not eligible for a credit under the following conditions:

(a) The Resource has been Postured for all or part of the hour;
(b) The Resource is a Limited Energy Resource that has been Postured during a prior hour in the Operating Day; or
(c) The Resource is an Intermittent Power Resource that is not a DNE Dispatchable Generator.

III.F.2.3.7.2. Settlement Period. For purposes of calculating Hourly Shortfall NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is eligible for an Hourly Shortfall NCPC Credit. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, to or from a Flexible DNE Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.

III.F.2.3.7.3. Eligible Quantity. The eligible quantity for each hour of the settlement period is:

(a) zero for a Fast Start Generator, a Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter, the Start-Up Fee and the No-Load Fee of the Supply Offer, or the total of the energy price parameter and the Interruption Cost of the Demand Reduction Offer, in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market for the hour is greater than the total of the corresponding energy price, Start-Up Fee, No Load Fee, and Interruption Cost parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9(e), the Start-Up Fee, No-Load Fee and energy at the Economic Minimum Limit are equal to $0, and (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9(f), the Start-Up Fee and No-Load Fee are equal to $0 and the energy at the requested dispatch level is the Energy Price Floor.

(b) zero for a Binary Storage DARD in the event the energy price parameter in the Demand Bid in the Real-Time Energy Market for the consumption cleared in the Day-Ahead Energy Market for the hour is less than the energy price parameter in the Demand Bid in the Day-Ahead Energy Market for the hour.

i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9 (e), then the energy price at the Minimum Consumption Limit is equal to the Demand Bid Cap, and; (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9 (f), then the energy price at the requested dispatch level for Binary Storage DARDs is the Demand Bid Cap.

(c) the Day-Ahead Economic Minimum Limit or Minimum Reduction for a non-Fast Start Generator, non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter of the Supply Offer or Demand Reduction Offer in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market above the Day-Ahead Economic Minimum Limit or Day-Ahead Minimum Reduction for an hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

and if neither (a) nor (b) nor (c) applies, then;

(d) the minimum of (i) the amount of energy cleared in the Day-Ahead Energy Market for an hour and (ii) the Resource's Economic Maximum Limit, Maximum Reduction, or a Limited Energy Resource limit imposed for the hour in the Real-Time Energy Market.

III.F.2.3.7.4. Credit Calculation (for non-Fast Start Generators, non-Fast Start Demand Response Resources, and non-Flexible DNE Dispatchable Generators). The Hourly Shortfall NCPC Credit for a Resource, other than a Fast Start Generator, a Fast Start Demand Response Resource, a Binary Storage DARD, or a Flexible DNE Dispatchable Generator, adjusted as described in III.F.1(h), is equal to:

(a) the greater of (i) zero and (ii) the total of (the Real-Time Price minus the Day-Ahead Price for an hour, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, multiplied by the Day-Ahead Economic Minimum Limit for the hour or the Day-Ahead Minimum Reduction for the hour) for all hours of the settlement period,

plus

(b) for each hour of the settlement period, for Generator Assets, the greater of (i) zero and (ii) the product of (1) the Real-Time Price minus the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, for an hour and (2) the eligible quantity minus the Day-Ahead Economic Minimum Limit for the hour; or, for Demand Response Resources, the greater of (i) zero and (ii) the product of (1) the Real Time Price minus the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, for an hour and (2) the eligible quantity minus the Day-Ahead Minimum Reduction for the hour.

III.F.2.3.7.5. Credit Calculation (for Fast Start Generators, Fast Start Demand Response Resources and Flexible DNE Dispatchable Generators). The Hourly Shortfall NCPC Credit for a Fast Start Generator, Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and (ii) the Real-Time Price minus the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, for an hour, multiplied by the eligible quantity for the hour, adjusted as described in III.F.1(h).

III.F.2.3.7.6 Credit Calculation (for Binary Storage DARDs). The Hourly Shortfall NCPC Credit for a Binary Storage DARD is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the Day-Ahead Locational Marginal Price minus the Real-Time Price for an hour, multiplied by the eligible quantity for the hour.

III.F.2.3.8. Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability

III.F.2.3.8.1. Eligibility for Credit. A Limited Energy Resource is eligible for real-time posturing NCPC credits for any Operating Day during which the Generator Asset has been Postured, when a request to minimize the as-bid production costs of the Generator Asset has been submitted. For purposes of calculating real-time posturing NCPC credits, the Generator Asset is treated as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Generator Asset was Postured, and if not the Generator Asset is treated as a non-Fast Start Generator. If the Generator Asset is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

III.F.2.3.8.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits for Limited Energy Resources, a settlement period is the period of one or more contiguous hours from the initiation of Posturing through the end of the Operating Day.

III.F.2.3.8.3 Resources Sharing a Single Fuel Source. When Limited Energy Resources that share a fuel source are Postured, for purposes of calculating real-time posturing NCPC credits the energy available to the Postured Generator Assets will be allocated among the Postured Generator Assets sharing the fuel source as indicated by estimates of available energy provided by the Lead Market Participant for each Generator Asset prior to Posturing.

III.F.2.3.8.4. Estimated Replacement Cost of Energy. The estimated replacement cost of energy is (i) the average of the Day-Ahead Locational Marginal Prices for hours ending 3 through 5 in the subsequent Operating Day for a Generator Asset that is part of an Electric Storage Facility, or (ii) the product of the oil index price multiplied by the oil-fired generator proxy heat rate for fuel oil-fired generating units, or (iii) zero for all other Generator Assets.
For fuel oil-fired generators, the oil index price is the ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation, and the oil-fired generator proxy heat rate is the average of the heat rate at Economic Min and the heat rate at Economic Max, where the heat rate at Economic Min is, for a Generator Asset, the average hourly energy price parameter of the Supply Offer at the Generator Asset's Economic Minimum Limit at the time of the Posturing decision divided by the oil index price, and the heat rate at Economic Max is, for a Generator Asset, the average hourly energy price parameter of the Supply Offer at the Generator Asset's Economic Maximum Limit at the time of the Posturing decision divided by the oil index price.

III.F.2.3.8.5. Estimated Revenue. The estimated revenue for a Generator Asset is the optimized energy output multiplied by the Real-Time Price for all hours in the settlement period. The optimized energy output is estimated for each hour by allocating the Postured energy to hours that the Generator

Asset would have operated had it not been Postured based on Real-Time Prices in the Operating Day, subject to the following conditions:

(a) the optimized energy output determination will take account of the Generator Asset's Economic Minimum Limit, and Economic Maximum Limit.
(b) the optimized energy output determination will take account of the estimated avoided cost of replacing energy that is not allocated to any hour and remains available at the end of the Operating Day.
(c) for non-Fast Start Generators, the optimized energy output is calculated for the contiguous hours from the time the Generator Asset is Postured until the available energy is depleted.

III.F.2.3.8.6. Estimated Avoided Replacement Cost. The estimated avoided replacement cost for an Operating Day is the remaining energy that would have been available at the end of the Operating Day had the Generator Asset operated in accordance with the optimized energy output determination in Section III.F.2.3.8.5, plus any increase in the remaining energy resulting from replenishment during the Operating Day after the Generator Asset is Postured, multiplied by the estimated replacement cost of energy.

III.F.2.3.8.7. Actual Revenue. The actual revenue for a Generator Asset is the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the settlement period.

III.F.2.3.8.8. Actual Avoided Replacement Cost. The actual avoided replacement cost for an Operating Day is the actual remaining energy at the end of the Operating Day multiplied by the estimated replacement cost of energy.

III.F.2.3.8.9. Credit Calculation. The real-time posturing NCPC credit for Limited Energy Resources is equal to the greater of (i) zero and (ii) the estimated revenue plus the estimated avoided replacement cost, minus the actual revenue plus the actual avoided replacement cost.

III.F.2.3.9. Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured for Reliability and for Demand Response Resources Postured for Reliability

III.F.2.3.9.1. Eligibility for Credit. Generator Assets (other than Limited Energy Resources) and Demand Response Resources are eligible for real-time posturing NCPC credits for the hours during which the Resource has been Postured.

III.F.2.3.9.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits, a settlement period is an hour during which the Generator Asset or Demand Response Resource is Postured.

III.F.2.3.9.3. Offer Used for Estimated Hourly Revenue and Cost.

(a) For a Generator Asset, the offer parameters used to estimate revenue and cost for an hour for purposes of calculating real-time posturing NCPC credits are:

  (i) Energy Price: the higher of the energy price parameter specified in (1) the Supply Offer for the hour at the time the ISO Postures the Generator Asset, or (2) the Supply Offer for the hour at the start of the hour;

  (ii) Start-Up Fee and No Load Fee: for Generator Assets Postured offline, the Start-Up Fee and No-Load Fee specified in the Supply Offer for the hour at the time the Generator Asset is Postured;

  (iii) for Generator Assets Postured to remain online but reduce output, the Start-Up Fee and No-Load Fee are calculated pursuant to Section III.F.2.2.2.3.

(b) For a Demand Response Resource, the offer parameters used to estimate revenue and cost for an hour for purposes of calculating real-time posturing NCPC credits are:

  (i) Energy Price: the higher of the energy price parameter specified in (1) the Demand Reduction Offer for the hour at the time the ISO Postures the Resource, or (2) the Demand Reduction Offer for the hour at the start of the hour;

  (ii) Interruption Cost: for a Demand Response Resource Postured to a demand reduction of zero MW, the Interruption Cost specified in the Demand Reduction Offer for the hour at the time the Demand Response Resource is Postured; for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MW, the Interruption Cost is calculated pursuant to Section III.F.2.2.2.3.

III.F.2.3.9.4. Estimated Hourly Revenue.

(a) The estimated hourly revenue for a Generator Asset is the optimized energy output multiplied by the Real-Time Price for the hour. The optimized energy output is estimated for each hour by determining where the Generator Asset would have operated had it not been Postured based on Real-Time Prices.

The optimized energy output determination will take account of the energy price parameter of the Supply Offer and the Generator Asset's Economic Minimum Limit and Economic Maximum Limit.

(b) The estimated hourly revenue for a Demand Response Resource is the optimized demand reduction multiplied by the Real-Time Price for the hour, where:

(i) The optimized demand reduction is estimated for each hour by determining where the Demand Response Resource would have operated had it not been Postured based on Real-Time Prices. The optimized demand reduction determination will take account of the energy price parameter of the Demand Reduction Offer and the Demand Response Resource's Minimum Reduction and Maximum Reduction.

III.F.2.3.9.5. Estimated Hourly Cost.

(a) The estimated hourly cost for a Generator Asset is the energy price parameter of the Supply Offer for the optimized energy output for the hour, plus the Start-Up Fee and the No-Load Fee, subject to the following conditions:

(i) For a Fast Start Generator Postured offline, the Start-Up Fee is included in each hour's cost and is not subject to apportionment;

(ii) For a non-Fast Start Generator Postured offline, the Start-Up Fee is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.

(b) The estimated hourly cost for a Demand Response Resource is the energy price parameter of the Demand Reduction Offer for the optimized demand reduction for the hour (where optimized demand reduction is determined pursuant to Section III.F.2.3.9.4(b)), plus the Interruption Cost, subject to the following conditions:

(i) For a Fast Start Demand Response Resource Postured to a demand reduction level of zero MW, the Interruption Cost is included in each hour's cost and is not subject to apportionment;

(ii) For a non-Fast Start Demand Response Resource Postured to a demand reduction of greater than zero MW, the Interruption Cost is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.

(c) A Generator Asset is treated as a Fast Start Generator and a Demand Response Resource is treated as a Fast Start Demand Response Resource for purposes of determining the estimated hourly cost only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator or non-Fast Start Demand Response Resource. If at the time the Resource is Postured the Generator Asset is offline, or the Demand Response Resource has not been dispatched, then its designation as a

Fast Start Generator or Fast Start Demand Response Resource is determined as of the time of the Posturing decision.

III.F.2.3.9.6. Actual Hourly Revenue. The actual hourly revenue for a Generator Asset or a Demand Response Resource is the sum of the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the hour.

III.F.2.3.9.7. Actual Hourly Cost.

(a) The actual hourly cost for a Generator Asset Postured to remain online but reduce output is the sum of the interval cost, which is the energy price parameter of the Supply Offer for the Metered Quantity For Settlement for the interval, plus the Start-Up Fee and No-Load Fee calculated pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Generator Asset Postured offline is zero.

(b) The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MW is the sum of the interval cost, which is the energy price parameter of the Demand Reduction Offer for the Metered Quantity For Settlement for the interval, plus the Interruption Cost calculated pursuant to pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to zero MW is zero.

III.F.2.3.9.8. Credit Calculation. The real-time posturing NCPC credit for a Generator Asset (other than a Limited Energy Resource) or a Demand Response Resource is equal to the greater of (i) zero and (ii) the estimated hourly revenue minus the estimated hourly cost, minus the actual hourly revenue minus actual hourly cost, adjusted as described in III.F.1(h).

III.F.2.3.10. Rapid Response Pricing Opportunity Cost NCPC Credits Resulting from Commitment of Rapid Response Pricing Assets

III.F.2.3.10.1. Eligibility for Credit. During any five-minute pricing interval in which a Rapid Response Pricing Asset is committed by the ISO and not Self-Scheduled, any Resource that is committed and able to respond to Dispatch Instructions during the interval is eligible to receive a Rapid Response Pricing Opportunity Cost NCPC Credit; provided, however, that such credit shall be zero if the Resource is non-dispatchable; the Resource has been Postured or has provided Regulation during the interval; if the Resource is a Settlement Only Resource, or if the Resource is an External Resource or External Transaction.

III.F.2.3.10.2. Economic Net Revenue or Economic Net Benefit.

(a) The economic net revenue for a Generator Asset or Demand Response Resource during the pricing interval is the Resource's optimized feasible energy quantity multiplied by the Real-Time Price, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.

(b) The economic net benefit for a Dispatchable Asset Related Demand during the pricing interval is the Resource's energy price parameter for its optimized feasible energy quantity as reflected in its Demand Bid, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the optimized feasible energy quantity multiplied by the Real-Time Price.

(c) The optimized feasible energy and reserve quantities are determined consistent with the Resource's offer or bid parameters, and are the energy and reserve quantities that maximize the Resource's economic net revenue or economic net benefit for the pricing interval, without changing the Resource's commitment status.

III.F.2.3.10.3. Actual Net Revenue or Actual Net Benefit.

(a) Except as provided in Section III.F.2.3.10.3(b), the actual net revenue for a Generator Asset or Demand Response Resource is the greater of: (i) the actual energy quantity supplied during the pricing interval multiplied by the Real-Time Price, plus the actual reserve quantity supplied during the pricing interval multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities; and (ii) the dispatched energy quantity multiplied by the Real-Time Price, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.

(b) The actual net revenue for a Generator Asset associated with an ATRR that has provided Regulation during the interval is equal to the dispatched energy quantity multiplied by the Real-Time Price, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.

(c) Except as provided in Section III.F.2.3.10.3(d), the actual net benefit for a Dispatchable Asset Related Demand is the greater of: (i) the energy price parameter for the actual energy quantity consumed as reflected in the Demand Bid, plus the actual reserve quantity supplied multiplied by the Real-Time Reserve Clearing Price, minus the actual energy quantity consumed multiplied by the Real-Time Price, and (ii) the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the dispatched energy quantity multiplied by the Real-Time price.

(d) The actual net revenue for a DARD associated with an ATRR that has provided Regulation during the interval is equal to the energy price parameter for the dispatched energy quantity as reflected in the

Demand Bid, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the dispatched energy quantity multiplied by the Real-Time price.

III.F.2.3.10.4. Credit Calculation. The Rapid Response Pricing Opportunity Cost NCPC Credit for a Resource is equal to the greater of: (i) zero; and (ii) the Resource's economic net revenue or economic net benefit for the interval less its actual net revenue or actual net benefit for the pricing interval.

The Rapid Response Pricing Opportunity Cost NCPC Credit for a Resource for an interval shall be reduced by the amount of any Real-Time Dispatch NCPC Credits for which the Resource is eligible for that interval, but shall be no less than zero.

III.F.2.4. Apportionment of NCPC Credits. For purposes of this Section III.F.2.4, any values previously established at the five-minute level shall be aggregated to create hourly values.

Each Day-Ahead Market NCPC Credit calculated pursuant to III.F.2.1.6 is apportioned to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue for all hours in the settlement period.

Each Real-Time Commitment NCPC Credit is apportioned as follows: (i) for the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the portion of the Commitment Period, and (ii) for all remaining intervals of the settlement period, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the period.

Each Hourly Shortfall NCPC Credit for a non-Fast Start Generator, a non-Fast Start Demand Response Resource or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator for energy cleared in the Day-Ahead Market at the Resource's Economic Minimum Limit or Minimum Reduction is apportioned to the hours in which the Real-Time Price exceeds the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, for all hours in the settlement period.

The following NCPC credits are assigned to the hours for which the credit was calculated:

- Day-Ahead Market NCPC Credits calculated pursuant to Section III.F.2.1.7.

- Real-Time Dispatch Lost Opportunity Cost NCPC Credits,
- Real-Time Dispatch NCPC Credits for all Resources,
- Day-Ahead External Transaction Import and Increment Offer NCPC Credits,
- Day-Ahead External Transaction Export and Decrement Bid NCPC Credits,
- Real-Time External Transaction NCPC Credits,
- Hourly Shortfall NCPC Credits for Fast Start Generators, Fast Start Demand Response Resources, Binary Storage DARDs and Flexible DNE Dispatchable Generators,
- Hourly Shortfall NCPC Credits for non-Fast Start Generators, non-Fast Start Demand Response Resources, and DNE Dispatchable Generators that are not Flexible DNE Dispatchable Generators for energy cleared in the Day-Ahead Energy Market above the Resource's Economic Minimum Limit or Minimum Reduction, and
- Rapid Response Pricing Opportunity Cost NCPC Credits as described in Section III.F.2.3.10.

III.F.2.5. NCPC Credit Designation for Purposes of NCPC Cost Allocation. Each hourly credit for Day-Ahead Market NCPC Credits, Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, Day-Ahead External Transaction Import and Increment Offer NCPC Credits, Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, Real-Time External Transaction NCPC Credits, Hourly Shortfall NCPC Credits, and Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured For Reliability and Demand Response Resources Postured For Reliability, and each daily credit for Real-Time Synchronous Condensing NCPC Credits, Cancelled Start NCPC Credits, Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability, and Rapid Response Pricing Opportunity Cost NCPC Credit is designated as first contingency, second contingency, voltage (VAR), distribution (SCR), ISO initiated audits and Minimum Generation Emergency consistent with the reason provided by the ISO when issuing a Dispatch Instruction for the Resource. If there is more than one reason provided by the ISO when issuing the Dispatch Instruction, the NCPC Credits are divided equally for purposes of the above designations. With the exception of Day-Ahead External Transaction Import and Increment Offer NCPC Credits and Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, the hourly credits are summed to determine the total credits for each NCPC Charge category for a day.

III.F.3. Charges for NCPC

III.F.3.1. Cost Allocation.

III.F.3.1.1 Day-Ahead Market NCPC Cost Allocation. NCPC costs for the Day-Ahead Energy Market are allocated and charged as follows:

(a) The total NCPC cost for the Day-Ahead Energy Market associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

(b) The total NCPC cost for the Day-Ahead Energy Market for resources designated as Special Constraint Resources in the Day-Ahead Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

(c) The total NCPC cost for the Day-Ahead Energy Market for resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.

(d) For each External Node, the total NCPC cost for Day-Ahead External Transaction Import and Increment Offer NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Load Obligations at the External Node for the hour.

(e) For each External Node, the total Day-Ahead External Transaction Export and Decrement Bid NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Generation Obligations at the External Node for the hour.

(f) All remaining NCPC costs for the Day-Ahead Market (except the NCPC costs for Storage DARDs) are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub).

(g) All remaining NCPC costs for the Day-Ahead Energy Market associated with Storage DARDs are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub) excluding Day-Ahead Load Obligations associated with Storage DARDs.

III.F.3.1.2. Real-Time Energy Market NCPC Cost Allocation. NCPC costs for the Real-Time Energy Market are allocated and charged as follows, subject to the conditions in Section III.F.3.1.3:

(a) The total NCPC cost for the Real-Time Energy Market associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are allocated and charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

(b) The total NCPC cost for the Real-Time Energy Market for resources designated as Special Constraint Resources in the Real-Time Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

(c) The total ISO initiated audit NCPC cost for resources performing an ISO initiated audit is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.

(d) The total NCPC cost for resources being Postured in the Real-Time Energy Market is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.

(e) The total NCPC cost for Rapid Response Pricing Opportunity Cost NCPC Credit during pricing intervals in which one or more Rapid Response Pricing Asset is committed in the Real-Time Energy Market (and not Self-Scheduled) is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.

(f) The total NCPC cost for the Real-Time Energy Market for resources identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.

(g) Total Minimum Generation Emergency Credits within a Reliability Region are allocated and charged hourly to Market Participants based on each Market Participant's pro rata share of Real-Time Generation Obligations, and positive Real-Time Demand Reduction Obligations, excluding that portion of a Market Participant's Real-Time Generation Obligation and Real-Time Demand Reduction Obligation within a Reliability Region that is eligible for a Real-Time Dispatch NCPC Credit pursuant to Section III.F.2.2.3 during a Minimum Generation Emergency.

(h) The total NCPC cost for Real-Time Dispatch Lost Opportunity Cost NCPC Credits is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.

(i) All remaining NCPC costs for the Real-Time Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of the absolute values of a Market Participant's (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day (excluding certain positive Real-Time Load Obligation Deviations as described in Section III.F.3.1.3(d)); (ii) generation deviations for Pool-Scheduled Resources not following Dispatch Instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following Dispatch Instructions, and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following Dispatch Instructions, including External Resources, in MWhs during the Operating Day; (iii) demand reduction deviations for Pool-Scheduled Demand Response Resources not following Dispatch Instructions; and (iv) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day. The Real-Time deviations calculation is specified in greater detail in Section III.F.3.2.

III.F.3.1.3 Additional Conditions for Real-Time Energy Market NCPC Cost Allocation.

(a) If a Generator Asset has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.

(b) If a Demand Response Resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the resource should not be dispatched in order to avoid a Minimum Generation Emergency, the Market Participant will be responsible for all Real-Time Demand Reduction Obligation Deviation charges, but will not incur related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.

(c) Any difference between the actual consumption (Real-Time Load Obligation) of a DARD and the DARD's Demand Bids that clear in the Day-Ahead Energy Market that result from operation in accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation for the purpose of allocating costs for Real-Time Energy Market NCPC Credits.

(d) In any hour during which a Capacity Scarcity Condition occurs or ISO New England Operating Procedure No. 4 or ISO New England Operating Procedure No. 7 are implemented, any NCPC Charges that would have been allocated pursuant to Section III.F.3.2 to net positive Real-Time Load Obligation Deviations in an affected Load Zone (and related portion of adjacent External Nodes) are instead allocated and charged to Market Participants based on their pro rata share of the sum of their Real-Time Load Obligation (excluding Real-Time Load Obligations associated with a Postured Dispatchable Asset Related Demand Resource) in all the affected Load Zones and (and related portion of adjacent External Nodes) during the affected hour(s). For purposes of this calculation, the ISO shall apportion any Real-Time Load Obligations and Real-Time Load Obligation Deviations at an External Node equally among the Load Zones to which the External Node is interconnected.

III.F.3.2 Market Participant Share of Real-Time Deviations for Real-Time Energy Market NCPC Credits.

Each Market Participant's pro-rata share of the Real-Time deviations for Real-Time Energy Market NCPC Credits is the following:

(a) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead Energy Market MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead Energy Market MWh or less than or equal to 5 MWh, then deviation = 0.

(b) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered output – cleared Day-Ahead Energy Market MWh) or (actual metered output – Real-Time Economic Minimum Limit) or (Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead Energy Market MWh or less than or equal to 5 MWh, then deviation = 0.

(c) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

plus,

(d) for each Pool-Scheduled Generator Asset and Continuous Storage Generator Asset:

(i) If the Generator Asset is not following Dispatch Instructions, has cleared the Day-Ahead Energy Market, has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output − Desired Dispatch Point) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

(ii) If the Generator Asset is not following Dispatch Instructions, has cleared the Day-Ahead Energy Market, has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – cleared Day-Ahead MWh) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead Energy Market MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

(e) for each Pool-Scheduled Demand Response Resource:

(i) If the Demand Response Resource is being dispatched, is not following Dispatch Instructions, has cleared in the Day-Ahead Energy Market, and has not been ordered to stop reducing demand for reliability purposes: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction − Desired Dispatch Point) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

(ii) If the Demand Response Resource is unavailable and has cleared in the Day-Ahead Energy Market: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction – cleared Day-Ahead MWh) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead Energy Market MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

(f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation,

where

(i) each Market Participant's Real-Time Load Obligation Deviation for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations (including the Hub), and

(ii) for purposes of calculating a Participant's Real-Time Load Obligation Deviation under this sub-section (e), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and

(iii) External Transaction sales curtailed by the ISO are omitted from this calculation.

plus,

(g) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation,

where

(i) each Market Participant's Real-Time Generation Obligation Deviation at External Nodes for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes, and

(ii) for purposes of calculating a Participant's Real-Time Generation Obligation Deviation under this sub-section (f), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and

(iii) External Transaction purchases curtailed by the ISO are omitted from this calculation.

plus,

(h) the absolute value of the total over all Locations of the Market Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

III.F.3.3 Local Second Contingency Protection Resource NCPC Charges.

Each Market Participant's pro-rata share of the cost for Day-Ahead Market NCPC Credits and Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection is based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region, excluding Real-Time Load Obligations associated with Storage DARDs subject to the following conditions:

(a) The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating a Market Participant's pro-rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

(b) For hours in which there is an NCPC cost for a resource providing Local Second Contingency Protection and ISO is selling Emergency Energy to an adjacent Control Area, the scheduled amount of Emergency Energy at the applicable External Node will be included in the calculation of a Market Participant's pro rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection as if the Emergency Energy sale were a Real-Time Load Obligation within each affected Reliability Region. The pro rata share calculated for the Emergency Energy transaction shall be included in the charges under an agreement for purchase and sale of Emergency Energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency Energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

External Node Common Name	**Associated Transmission Facilities**	**Reliability Region(s)**	**Allocator**
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390/3016) tie line	Maine	100% to Maine
HQ Phase I/II External Node	HQ-Sandy Pond 3512 & 3521 Lines	West Central Massachusetts	100% to West Central Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-7 Line) Hoosick- Bennington Line (K-6 Line) Rotterdam – Bearswamp Line (E205W Line) Alps – Berkshire Line (393Line) Pleasant Valley – Long Mountain Line (398 Line)	Vermont, Vermont Vermont West Central Massachusetts West Central Massachusetts Connecticut	Allocated proportionally to the Vermont, West Central Massachusetts and Connecticut Reliability Regions based on the Normal Limits as described in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
NY NNC External Node	Northport-Norwalk Harbor (601,602 and 603 Lines)	Connecticut	100% to Connecticut
NY CSC External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(c) For each month, the ISO performs an evaluation of total Local Second Contingency Protection Resource NCPC Charges for each Reliability Region. If, for any Reliability Region, the magnitude of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph c, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency Energy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a Storage DARD.

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ > .06 X Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$

Condition 2 – is the Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ > 2 X Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\text{\%}}$ $_{\text{(Reliability Region)}}$

Where:

Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) divided by the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ equals the sum of the prior 12 months' values, not including the current month, of Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ divided by 12. (For the purposes of other calculations which include the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$, a value of .001 will be substituted for any Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ is triggered.

(ii) Determination of the portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated –

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated = Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ X Min (Condition 1 Rate $_{\text{(Reliability Region, month)}}$, Condition 2 Rate $_{\text{(Reliability Region, month)}}$)

Where:

Condition 1 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus .06 times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Condition 2 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus 2 times the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\text{\% (Reliability Region)}}$ times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

(iii) Determination of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

(Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ / Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

(Regional Network Load $_{\text{(Transmission Customer, Reliability Region, month)}}$ / Regional Network Load $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Regional Network Load $_{\text{(Reliability Region, month)}}$ equals:

The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

Regional Network Load $_{\text{(Customer, Reliability Region, month)}}$ equals:
The Transmission Customer's monthly MWh of Regional Network Load in the Reliability Region.

III.F.4. NCPC Reporting

III.F.4.1. Zonal NCPC Report. Beginning January 2019, for each month, no later than 20 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating the aggregate dollar amount of NCPC Credits by category paid to the resources located in each Load Zone for each day during that month.

III.F.4.2. Resource-Specific NCPC Report. Beginning January 2019, for each month, no later than 90 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating the name of each resource that received NCPC

Credits for that month and the total dollar amount of NCPC Credits that each of those resources received for that month.

III.F.4.3. Operator-Initiated Commitment Report. Beginning January 2019, for each month, no later than 30 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating each resource commitment made during that month after the Day-Ahead Energy Market for a reason other than minimizing the total production costs of serving load. For each such commitment, the report shall include the start time, the Economic Maximum Limit or Maximum Reduction of the committed resource, the Load Zone in which the committed resource is located, and the reason for the commitment.

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