NEPOOL
NEW ENGLAND POWER POOL
Sebastian Lombardi
Secretary

November 24, 2026

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of December 3, 2026 Participants Committee Annual Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the 2026 Annual Meeting of the Participants Committee will be held **in person on Thursday, December 3, 2026, at 10:00 a.m. at the Colonnade Hotel, located at 120 Huntington Avenue, Boston, MA 02116**, for the purposes set forth on the attached agenda and posted with the meeting materials at https://nepool.com/meetings/.

Please note the following:

- ***Holiday Breakfast***: A holiday breakfast, providing attendees with an opportunity to begin the day by sharing a few moments of the holiday season, will begin at 8:45 a.m.

- ***Sector Changes***: Participants wishing to change Sector membership for 2027 must provide us with written notice of that request *before* the Annual Meeting. Under Section 6.3 of the NEPOOL Agreement, any Participant request to change the Sector in which it votes becomes effective at the first Annual Meeting following that request.

To join the meeting using the enhanced Webex interface, please **download the Webex app** to your desktop or to your phone (whichever device you will be using) **in advance of the meeting** and use the app to join the meeting. You may also access the meeting through the ISO's Webex meetings page by clicking https://iso-newengland.webex.com/webappng/sites/iso-newengland/meeting/home and selecting the meeting (event password = **nepool**).

Respectfully yours,

/s/
Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the November 12, 2026 Participants Committee meeting. A copy of the draft minutes are included with this supplemental notice and posted with the meeting materials.

2. To adopt and approve the actions recommended by the Reliability Committee set forth on the Consent Agenda included with this supplemental notice and posted with the meeting materials.

3. To receive remarks from Chairman Laura V. Swett of the Federal Energy Regulatory Commission.

4. To receive summaries of the ISO Board and Board Committee meetings held since the last summaries were circulated. The summaries are included with this supplemental notice and posted with the meeting materials.

5. To receive a System and Market Operations Report. The December System and Market Operations Report, reflecting November data, will be circulated and posted in advance of the meeting.

6. To receive the 2026 NEPOOL Annual Report.

7. To elect NEPOOL Participants Committee Officers for 2027. A draft resolution reflecting the outcome of the balloting for Participants Committee Chair, as well as candidates for Secretary and Assistant Secretary, is included with this supplemental notice and posted with the meeting materials.

8. To adopt a NEPOOL Budget for 2027. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

9. To consider and take action, as appropriate, on Billing Policy revisions in response to the FERC's September 10, 2026 *Correction Mechanism Compliance Order*. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

10. To consider and take action, as appropriate, on the following Tariff revisions reflecting the ISO's Capacity Auction Reforms – Seasonal Accreditation (CAR-SA) proposal:

    a. Section I.2.2 (Definitions) and Market Rule 1, including Appendices A (Market Monitoring, Reporting and Market Power Mitigation) and F (NCPC Accounting), as recommended by the ***Markets Committee*** at its November 4-5 meeting;

    b. Section I.2.2 and Market Rule 1 Sections III.1.5 and III.12, as unanimously recommended by the ***Reliability Committee*** at its November 17 meeting;

    c. Section I.2.2, Sections II.48 through II.55.3, and OATT Attachment K (RSP Process), to be considered by the ***Transmission Committee*** at its November 19 meeting; and

    d. Section I.2.2, Billing Policy and Financial Assurance Policy, to be considered by the ***Budget & Finance Subcommittee*** at its November 20 meeting.

    Background materials and draft resolutions are included with this supplemental notice and posted with the meeting materials.

Protocols. The NEPOOL general business portions and plenary sessions of the meeting will be recorded, as are all the NEPOOL Participants Committee meetings. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those participating in this meeting must identify themselves and their affiliation at the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

11. To receive a report on current contested matters before the FERC and the Federal Courts. The litigation report will be circulated and posted in advance of the meeting.

12. To receive reports from Committees, Subcommittees and other working groups:

- Markets Committee
- Reliability Committee
- Transmission Committee
- Budget & Finance Subcommittee
- Membership Subcommittee
- Joint Nominating Committee

13. Administrative matters.

14. To transact such other business as may properly come before the meeting.

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PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 2:00 p.m. on Thursday, November 12, 2026, at the Hilton Boston Back Bay in Boston, Massachusetts. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates who participated in the meeting, either in person or by Webex.

Ms. Sarah Bresolin, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Ms. Bresolin welcomed the members, alternates and guests who were present, including members of the ISO Board and representatives of the New England States.

APPROVAL OF OCTOBER 2, 2026 MEETING MINUTES

Ms. Bresolin referred the Committee to the preliminary minutes of the October 2, 2026 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, subject to additional non-material clarifications, with an abstention by Mr. Jon Lamson noted.

CONSENT AGENDA

Ms. Bresolin then referred the Committee to the Consent Agenda that had been circulated and posted in advance of the meeting. The Consent Agenda included three items recommended by the Reliability Committee (RC): (i) revisions to Planning Procedure No. 7 concerning potential extensions of, or limited waivers from, compliance with FERC Order No. 881; (ii) Hydro-Québec Interconnection Capability Credit values for the third Annual Reconfiguration Auction for the 2027-28 Capacity Commitment Period; and (iii) the Installed Capacity

Requirement (ICR) and related values and Marginal Reliability Impact demand curves for that auction.

Following motion duly made and seconded, the Consent Agenda was approved, with oppositions by CSC and LIPA (each for its long-standing and articulated objections to the ISO's determination that the Cross-Sound Cable has no capacity import capability into New England, disregarding what they asserted is the project's demonstrated reliability benefits to Connecticut and the region, particularly through the procurement of emergency energy over the facility), and abstentions by BP, DTE, Galt, Mercuria, and Mr. Lamson.

EXCLUSION OF SATOAS FROM ENERGY TRANSACTION UNITS

Mr. Tom Kaslow, Budget & Finance Subcommittee (B&F) Chair, referred the Committee to proposed conforming changes to Section IV.A, Schedule 2 of the Tariff concerning Storage as Transmission-Only Assets (SATOAs). He explained that SATOAs are used exclusively for transmission purposes and do not participate in the wholesale markets, except for charging and discharging necessary to perform their transmission functions. Consistent with that role, the proposed changes would exclude SATOA operations from the calculation of Energy Transaction Units (ETUs). Mr. Kaslow reported that the B&F had considered the changes at its October 9, 2026 meeting, that no member had expressed opposition or concern, and that no objection had been raised to advancing the proposal to the Participants Committee.

There being no questions, the following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the updates to Section IV.A, Schedule 2 of the Tariff to exclude the operation of Storage as Transmission-Only Assets from the calculation of Energy Transaction Units, as reflected in the materials circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

Without discussion, the motion was unanimously approved, with an abstention by Mr. Lamson noted.

ISO CHIEF EXECUTIVE OFFICER REPORT

Dr. Vamsi Chadalavada, ISO President and Chief Executive Officer, reported on the ISO's five-year strategic plan, which the ISO Board had approved at its November 10, 2026 open meeting. He said that the ISO's mission remained unchanged and that the plan was intended to strengthen the ISO's effectiveness, agility and responsiveness as a service organization. He identified three aspirations for 2032: that the ISO be viewed as a valued partner; that reliable system operation be supported by competitive markets; and that the ISO be a destination for, and workplace of choice among, talented professionals.

Using slides from his report, Dr. Chadalavada reviewed eight strategic opportunities: (i) Capacity Auction Reform implementation and related improvements; (ii) implementation of temporally optimized pricing and dispatch; (iii) measures to bolster the existing grid and resource fleet and support commercial viability; (iv) a stakeholder-accessible resource adequacy simulation platform; (v) expanded access to data through a universal data platform, subject to appropriate security and confidentiality protections; (vi) implementation of the Asset Condition Reviewer function; (vii) better alignment of demand flexibility programs across retail and wholesale markets; and (viii) a platform to facilitate forward transactions. He identified artificial intelligence as an enabling strategic tool supporting those opportunities.

Dr. Chadalavada emphasized that the strategic plan was a living document and did not itself decide the design or timing of any particular initiative. Individual proposals would return through the applicable stakeholder process. The ISO intended to use the plan to prioritize work across the 2028-32 period, rather than solely through an annual planning cycle, and expected to

return in the first quarter of 2027 with further information and opportunities for stakeholder input.

In discussion, a participant expressed support for the proposed forward-transactions platform and the opportunity for improved hedging against load and capacity-price volatility. In response to a question from Ms. Bresolin regarding the cadence for updating the plan, Dr. Chadalavada said that initiative-specific changes would proceed through the appropriate committees and broader changes could be addressed at the Participants Committee. He reiterated that the ISO would provide a further prioritization update in the first quarter of 2027.

ISO WINTER 2026/27 OUTLOOK AND SYSTEM & MARKET OPERATIONS REPORT

Mr. Stephen George, ISO Vice President of System & Market Operations and Capital Projects, referred the Committee to the November System & Market Operations Report (Report), which had been circulated and posted in advance of the meeting. He reviewed highlights from the Report, noting that it included data through October 31, 2026, unless otherwise noted. Those highlights included: (i) the Peak Hour for October 2026, with 16,106 MW of Revenue Quality Metered (RQM) Data, occurred on October 2, 2026 during the hour ending at 6:00 p.m.; (ii) October averages for Day-Ahead Hub Locational Marginal Price (LMP) ($39.26/MWh), Real-Time Hub LMP ($37.48/MWh), and natural gas prices ($1.46/MMBtu); (iii) an Energy Market value for October 2026 of $412 million, down 8% from September 2026 and down 12% from October 2025; (iv) an Ancillary Services Market value of $10 million, up 41% from September 2026 and down 42% from October 2025; (v) average Day-Ahead cleared physical energy during peak hours as a percentage of forecasted load, which was lower than in September 2026; (vi) Net Commitment Period Compensation (NCPC) payments for October totaled $3 million (representing 0.7% of October's monthly Energy Market value), consisting of $3 million in First

Contingency payments (including $521,000 in Dispatch Lost Opportunity Costs, $156,000 in Rapid Response Pricing Opportunity Costs, $775,000 in Generator Performance Auditing payments, and $394,000 paid to resources at external locations, up $185,000 from September, with $3,000 of those external-location costs charged to Real-Time Deviations); and (vii) a Forward Capacity Market (FCM) value of $78 million.

Using slides from the Report, Mr. George then (i) highlighted month-over-month and year-over-year increases in output from storage, solar and wind resources, noting that Vineyard Wind and Revolution Wind had become fully commercial and that the Report now separately identified onshore and offshore wind production; (ii) reported that the recently approved Day-Ahead Ancillary Services (DAAS) adjustments, including changes to the strike-price adjustment and Forecast Energy Requirement demand-quantity adjustment, became effective in the October 22 Day-Ahead Market for the October 23 Operating Day and were performing as expected; (iii) noted that the transmission outages identified in the prior month's Report were expected to conclude during November and that minimal planned transmission outages were anticipated during the winter; (iv) reported that, effective November 1, 2026, the ISO reduced the Reserve Non-Performance Factor from 115% to 110%, continuing the reduction from 120% to 115% implemented on May 1, 2026; and (v) reported that, also effective November 1, the ISO reduced the Unit Dispatch System look-ahead interval from 15 minutes to 10 minutes. Mr. George said that the shorter look-ahead interval, which was implemented in response to a NEPOOL priority request, was operating as expected and represented the first of several storage-dispatch enhancements under consideration.

In response to comments regarding the approximately 11 days' notice provided for the Reserve Non-Performance Factor change, Mr. George acknowledged that market participants

may have contracts, power purchase agreements and other transactions affected by such changes. He agreed that similar discretionary changes in the future could warrant additional advance notice or a more predictable review schedule, while preserving the ISO's ability to respond to system needs. Mr. George said that the ISO expected to maintain the 110% factor through the winter, would continue to monitor performance, and did not anticipate another adjustment before the spring.

In response to other comments, Mr. George agreed to discuss offline the level and timeliness of NCPC information included in future Reports. He acknowledged that the ISO's weekly and monthly market reports were less timely than the information presented to the Committee and said that the ISO would consider whether a streamlined approach could continue to provide the NCPC information most useful to participants. In response to favorable comments regarding the shorter Unit Dispatch System look-ahead interval, Mr. George said that the ISO expected to present additional storage-dispatch enhancements for stakeholder consideration in 2027.

Mr. George then presented the ISO's Winter 2026/27 Outlook. He said that El Niño conditions could result in greater temperature variability and additional coastal storms, although the National Oceanic and Atmospheric Administration projected a 50%-60% probability of above-average temperatures across most of New England. The ISO's 50/50 and 90/10 winter peak demand forecasts were 20,483 MW and 21,457 MW, respectively, slightly higher than the prior year's forecasts. The prior winter's peak demand was 20,182 MW, recorded on January 25, 2026.

Turning to available supply, Mr. George highlighted the expected winter contribution of the region's two newly commercial offshore wind facilities, noting that Winter 2026-27 would

be the ISO's first opportunity to observe their performance throughout an entire winter season. He also noted that no significant generation outages were scheduled and that there had been no material resource retirements since Winter 2025-26. Fuel-oil inventories were several percentage points higher than at the same time in 2025 (approximately 44% full), with inventories expected to reach approximately 50% before December 1. Mr. George said that fuel supplies appeared to be available, although global conditions could result in longer delivery times. He emphasized that timely replenishment of stored fuels would remain important throughout the winter.

Mr. George also noted that Winter 2026-27 would be the first full winter with the New England Clean Energy Connect facility (NECEC) in service. The ISO expected NECEC to deliver energy during most periods, although transfers could be limited during peak conditions in Québec. He said that the ISO continued to communicate and coordinate with Québec and the other neighboring Control Areas regarding expected conditions and available transfers.

Using its Probabilistic Energy Adequacy Tool (PEAT), Mr. George reported that the ISO evaluated extreme winter conditions, including conditions comparable to Winter 2025-26's 19-day cold period. Mr. George reported that the modeled energy shortfall magnitude and duration were well below the Regional Energy Shortfall Threshold (REST) criteria. The ISO's winter preparations included participant surveys, training seminars, audits of dual-fuel resources and weekly 21-day energy assessments, with the frequency of those assessments to increase if system conditions warranted. Mr. George said that lessons from the prior winter included the effectiveness of the ISO's existing market and operational tools, the importance of timely fuel replenishment, and the value of continued collaboration among the ISO, market participants, and state and federal partners. No questions were raised regarding the Winter 2026/27 Outlook.

LARGE LOAD REVISIONS

Mr. Dave Burnham, Transmission Committee (TC) Vice-Chair, referred the Committee to proposed Tariff revisions concerning the integration of Large Loads (Large Load Revisions or Proposal). He explained that the Revisions had been developed by the ISO and Participating Transmission Owners (PTOs) in response to the FERC's June 18, 2026 order in Docket No. EL26-72 (Show-Cause Order). He explained that the Proposal defined Large Loads and created three new transmission-service options, a study process, operational requirements, price-based redispatch provisions, settlement and cost-recovery rules, and resource-adequacy treatment. He said that the ISO expected to address Bring Your Own New Capacity requirements in a subsequent 2027 stakeholder process.

Mr. Burnham then summarized the Committee process undertaken to review the Large Load Revisions, which had culminated in Votes by each of the Technical Committees on November 3. He reported that each of the TC and RC had recommended, with limited opposition and abstentions, Participants Committee support for the Large Load Revisions within their areas of responsibility; the Markets Committee (MC) had also recommended Participants Committee support for the Large Load Revisions within its area of responsibility by a 71.11% Vote in favor.

Following an opportunity for clarifying questions (none were asked), Ms. Bresolin indicated that the Technical Committee recommendations would each be considered and voted separately, with a procedural motion expected with respect to the vote on the TC-recommended revisions.

TC-Recommended Revisions

The Committee began with the following main motion, which was duly made and seconded:

> RESOLVED, that the Participants Committee supports the Large Load Revisions in response to the FERC's Order in Docket No. EL26-72, as proposed by ISO-NE and the PTOs and as recommended by the Transmission Committee, and as reflected in the materials distributed to the Participants Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.

MA AGO Motion to Divide the Question

Ms. Bresolin then recognized the member for the Massachusetts Attorney General's Office (MA AGO), who wished, for the reasons set forth in the MA AGO's memo circulated in advance of the meeting, to divide consideration of the TC-Recommended Revisions so that that the PTOs' proposed Large Load Cost Recovery Agreement (Attachment V) would be considered and voted on separately from the remainder of the TC-recommended changes. She explained that the division would procedurally permit separate consideration of the Proposal's cost allocation provisions and would allow for an opportunity to provide the FERC with a more granular description of the support for the Proposal overall and the specific, limited objections raised in connection with the PTO's cost allocation and recovery proposal. Following clarification, the non-debatable motion to divide was duly made, seconded and determined by a show of hands to have been approved.

Vote on the TC-Recommended Changes Excluding Attachment V

Without further discussion, the Committee then considered a motion to support the TC-recommended Large Load Revisions (excluding Attachment V). That motion was approved by a

show of hands, with oppositions by Constellation, CPV, NRG, Pawtucket, Shell, and Vistra, and abstentions by Canal Marketing, Clearway, Emera, Mercuria, Wheelabrrator, and Mr. Lamson.

Vote on the TC-Recommended Large Load Cost Recovery Agreement (Attachment V)

Committee discussion then turned to separate consideration of the proposed Large Load Cost Recovery Agreement. Mr. Burnham, speaking in his capacity as PTO Administrative Committee (PTO-AC) Chair, explained that, under the proposed Attachment V, network-upgrade costs associated with Large Loads would be included in regional transmission rates, but only to the extent that doing so would not increase the Regional Network Service (RNS) rate; if inclusion of those costs would increase that RNS rate, Appendix C-2 would assign the resulting amount to the Large Load transmission customer, holding other customers harmless from a rate increase. He summarized what the PTOs believed were the merits of its Proposed Attachment V, including that the approach (i) was consistent with the FERC's longstanding transmission pricing policy, (ii) would recognize the regional benefits that network upgrades for large loads could provide under certain conditions, and (iii) and would create incentives for new load to site where they would not trigger significant network upgrades.

Members expressed appreciation for the efforts of the ISO and the PTOs, particularly given the compulsory, compressed timeframe. Several End Users explained their opposition to the proposed allocation, citing concerns that the cost allocation methodology and attendant risk of cost shifting did not sufficiently protect rate payers. They argued that hyperscale Large Loads presented circumstances different from traditional load growth; that existing customers should not lose rate reductions that otherwise would result when new load entered the regional rate divisor; and that new Large Loads should bear both the embedded and incremental costs associated with their interconnection (as being considered in proposed federal legislation).

PTO representatives responded that network upgrades had traditionally been regionalized, that a Large Load would contribute to embedded regional costs through its increased load-ratio share, and that the proposed rate test struck a reasonable balance by ensuring that existing customers' rates would not increase.

Without further discussion, the Committee then considered the following motion:

> RESOLVED, that the Participants Committee supports Attachment V (Large Load Cost Recovery Agreement, including Appendix C-2), as proposed by the PTOs in response to the FERC's order in Docket No. EL26-72 and recommended by the Transmission Committee, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.

The Committee did not approve the motion to support Attachment V. The motion, which required a 66.67% Vote in favor to be approved by the Committee, failed to pass with a 63.39% Vote in favor (Generation Sector – 0.0%; Transmission Sector – 16.67%; Supplier Sector – 9.52%; Alternative Resources Sector – 11.11%; Publicly Owned Entity Sector – 16.67%; and End User Sector – 9.42%) (*See* Vote 1 on Attachment 2).

RC-Recommended Revisions

The Committee then moved to the portions of the Large Load Revisions recommended by the RC, which would exclude Large Loads receiving Interim Contract Demand Service or Non-Firm Contract Demand Service from the calculation of the Installed Capacity Requirement and related values.

Without discussion, the following motion was duly made, seconded and approved by a show of hands, with oppositions by Constellation, CPV, NRG, Pawtucket, and Shell, and abstentions by Canal Marketing, Clearway, Dartmouth Power, EDF, Emera, LIPA, Mercuria, and Wheelabrator:

> RESOLVED, that the Participants Committee supports the Large Load Revisions in response to the FERC's Order in Docket No. EL26-72, as proposed by ISO-NE and the PTOs and as recommended by the Reliability Committee, and as reflected in the materials distributed to the Participants Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Reliability Committee.

MC-Recommended Revisions

Moving to the portions of the Large Load Revisions recommended by the MC, which included metering and dispatch requirements; ineligibility of Large Loads to provide Real-Time Reserves or Day-Ahead Ancillary Services; provisions allowing redispatchable Large Load demand to help set Day-Ahead and Real-Time Locational Marginal Prices when that demand is marginal; and the exclusion of Interim and Non-Firm Contract Demand Service from capacity-cost allocation, the following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the Large Load Revisions in response to the FERC's Order in Docket No. EL26-72, as proposed by ISO-NE and the PTOs and as recommended by the Markets Committee, and as reflected in the materials distributed to the Participants Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Thanking the ISO, PTOs and Participants for all of their hard work, an End User Participant explained his opposition, which he attributed to the impact on customers from increased Energy Market and Capacity prices.

Without further discussion, the Committee then approved the motion with a 68.92% Vote in favor (Generation Sector – 0.0%; Transmission Sector – 16.67%; Supplier Sector – 8.337%; Alternative Resources Sector – 12.96%; Publicly Owned Entity Sector – 16.67%; and End User Sector – 14.29%) (*See* Vote 2 on Attachment 2).

LITIGATION REPORT

Mr. Lombardi referred the Committee to the Litigation Report, which had been circulated and posted before the meeting. He highlighted the FERC's acceptance of the Asset Condition Reviewer proposal, which included separate concurrences of Commissioners Rosner and Chang, each of which favorably noted the New England stakeholder process and the spirit of collaboration among the States, NEPOOL and the ISO that made proposal possible. He reported that the 2027 ISO and NESCOE Budget filings remained pending before the FERC and noted the continued activity in proceedings related to the first Transitional Cluster Study and the allocation of costs arising from that Study. He encouraged those with questions on the matters highlighted, or any matter in the Litigation Report, to reach out to NEPOOL Counsel.

COMMITTEE REPORTS

Markets Committee. On behalf of MC Vice-Chair Ben Griffiths, Ms. Bresolin stated that the next MC meeting would be held virtually on December 8, 2026, and would include discussion of the negative-pricing proposal.

Reliability Committee. Mr. Frank Ettori, RC Vice-Chair, reported that the next RC meeting would be held in person at the DoubleTree in Westborough, Massachusetts on November 17, 2026. The agenda would include the RC's vote on its portions of the ISO's Capacity Auction Reforms — Seasonal/Accreditation (CAR-SA) proposal, a Central Maine Power (CMP) Proposed Plan Application (PPA), several Transmission Cost Allocations (TCAs), proposed revisions to Operating Procedures (OP) Nos. 2, 13 and 14, an introduction to proposed changes to OP-5, and proposed Planning Procedure No. 4 cost-category revisions.

Transmission Committee. Mr. Dave Burnham, TC Vice-Chair, reported that the next TC meeting would be held in person on November 19, 2026, also at the DoubleTree in

Westborough. The agenda would include the TC's vote on its portions of the CAR-SA Proposal, continued discussion of *Order 1920* compliance; discussion of the disbursement of withdrawal penalties from the Transitional Cluster Study, and an initial presentation on Transmission right-sizing.

Budget & Finance Subcommittee (B&F). Mr. Tom Kaslow, B&F Chair, reported that the next B&F meeting would be held on November 20, 2026 and would include proposed Capacity Auction Reform-related changes to the Financial Assurance Policy.

Membership Subcommittee. Mr. Brian Thomson, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting would be held virtually the following day to consider two membership applications and two terminations.

ADMINISTRATIVE MATTERS

Mr. Lombardi reported that the next Participants Committee meeting would be held on Thursday, December 3, 2026 at the Colonnade Hotel in Boston. In keeping with the Committee's year-end tradition, a holiday breakfast would precede the meeting. All were encouraged to attend. FERC Chairman Laura V. Swett and members of her senior staff were

expected to attend, and participants were invited to submit suggested questions to Ms. Bresolin or Mr. Lombardi in advance.

Mr. Patrick Gerity, Assistant Secretary, reminded Participants that any notice of an election to change Sectors for 2027 must be delivered before the December meeting commenced.

There being no other business, the meeting adjourned at 3:35 p.m.

Respectfully submitted,

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Sebastian Lombardi, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE NOVEMBER 12, 2026 MEETING

(W) = Webex

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Joe LaRusso (W)		
Advanced Energy United	Assoc. Non-Voting		Alex Lawton (W)	
AR Large RG Group Member	AR-RG		Aidan Foley (W)	
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
AVANGRID (CMP/UI)	Transmission	Jaimie St. Pierre	Jason Rauch	Alan Trotta (W)
Bath Iron Works	End User			Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		Michael Lazorchak
Boylston Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
BP Energy Company (BP)	Supplier		Christine Huhgey (W)	José Rotger
Braintree Electric Light Department	Publicly Owned Entity	Dave Cavanaugh		Michael Lazorchak
Brookfield Energy Trading and Marketing LLC	Supplier	Aleks Mitreski		
Canal Marketing LLC	Generation		Bill Fowler (W)	
Chester Municipal Light Department	Publicly Owned Entity		Dan Murphy	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Clear River Electric	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
CLEAResult Consulting Inc.	AR-DG	Tamera Oldfield (W)		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (W)		
Connecticut Office of Consumer Counsel	End User	Claire Coleman	Jamie Talbert-Slagle	
Conservation Law Foundation	End User			Anxhela Mile (W)
Constellation Energy Generation (Constellation)	Supplier		Gretchen Fuhr	Bill Fowler (W)
CPV Towantic, LLC	Generation	Richard Bratton		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Dartmouth Power Associates, L.P.	Generation	Carrie Hitt		Sarah Yasutake (W)
DTE Energy Trading, Inc. (DTE)	Supplier			José Rotger
Earthjustice	End User		Ada Statler (W)	Jennifer Yun (W)
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services	Supplier			Bill Fowler (W)
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin (W)		
Environmental Defense Fund	End User	Jolette Westbrook (W)		
Eversource Energy	Transmission	Vandan Divatia	Dave Burnham	
Fiscal Alliance Foundation, Inc.	End User			Lisa Linowes (W)
Gabel Associates, Inc.	Supplier	Sarah Yasutake (W)		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati (W)	
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation		Steve Kirk	Bill Fowler (W)
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Green Oceans	End User		Lauren Knight (W)	Lisa Linowes (W)
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Hammond Lumber Company	End User			Bill Short
Harvard Dedicated Energy Limited	End User			Doug Hurley
High Liner Foods (USA) Inc.	End User		Bill Short	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Holden Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
H.Q. Energy Services (US)	AR-RG	Louis Guilbault (W)		
Hudson Light and Power Department	Publicly Owned Entity			Dave Cavanaugh
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Industrial Wind Action Corp	End User	Lisa Linowes (W)		

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE NOVEMBER 12, 2026 MEETING

(W) = Webex

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Lamson, Jon	End User	Jon Lamson		
Littleton (MA) Electric Light and Water Dept.	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar (W)		
Maine Power LLC	Supplier	Jeff Jones (W)		
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Mass. Attorney General's Office (MA AG)	End User	Jackie Bihrle	Jamie Donovan	Chris Modlish (W) Caroline Palmer (W)
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Mass. Department of Capital Asset Management	End User		Paul Lopes (W)	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide	Dan Murphy	
MDC – The (CT) Metropolitan District	Publicly Owned Entity		Dave Cavanaugh	
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Midcoast Regional Redevelopment Authority	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Moore Company	End User			Bill Short
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Gens. Assoc. (NEPGA)	Assoc. Non-Voting	Bruce Anderson	Dan Dolan	
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw (W)
New Hampshire Office of Consumer Advocate	End User	Matthew Fossum		
NextEra Energy Resources, LLC	Generation	Michelle Gardner	Nick Hutchings	
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
NRG Business Marketing, LLC	Supplier	Ben Griffiths (W)		
Nylon Corporation of America	End User			Bill Short
Pawtucket Power Holding Company (Pawtucket)	Generation	Dan Allegretti	Tom Kaslow	
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
PowerOptions, Inc.	End User			Doug Hurley
Princeton Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
RENEW Northeast, Inc.	Assoc. Non-Voting	Francis Pullaro		Carter Scott (W)
Rhode Island Energy (Narragansett Electric Co.)	Transmission	Brian Thomson	Robin Lafayette	
RI Division (DPUC)	End User		Christy Hetherington	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide	Dan Murphy
Saint Anselm College	End User			Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	Dan Murphy
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
SYSO Inc.	AR-DG			Alex Worsley
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Veolia Flexible Energy Services North America	AR-LR	Doug Hurley		
Vermont Electric Company	Transmission	Frank Ettori		
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny (W)		
Vermont Energy Investment Corp.	AR-LR			Doug Hurley

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE NOVEMBER 12, 2026 MEETING

(W) = Webex

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (W)
Versant Power	Transmission	Dave Norman		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Vistra (Dynegy Marketing and Trade, Inc.)	Generation	Ryan McCarthy		Bill Fowler (W)
Vitol Inc.	Supplier	Seth Cochran		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	Michael Lazorchak
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler (W)	
ZTECH, LLC	End User			Bill Short

NOVEMBER 12, 2026 PARTICIPANTS COMMITTEE MEETING
ROLL CALL VOTES

Vote 1: Attachment V (Large Load Cost Recovery Agreement).
Vote 2: MC-recommended Large Load Revisions.

TOTAL

Sector/Group	Vote 1	Vote 2
GENERATION	0.00	0.00
TRANSMISSION	16.67	16.67
SUPPLIER	9.52	8.33
ALTERNATIVE RESOURCES	11.11	12.96
PUBLICLY OWNED ENTITY	16.67	16.67
END USER	9.42	14.29
% IN FAVOR	**63.39**	**68.92**

GENERATION SECTOR

Participant Name	Vote 1	Vote 2
Canal Marketing LLC	A	O
CPV Towantic, LLC	O	O
Dartmouth Power Associates	A	A
Generation Bridge Companies	A	A
Pawtucket Power Holding Co.	O	O
Vistra (Dynegy Mktg and Trade, LLC)	O	O
IN FAVOR (F)	0	0
OPPOSED (O)	3	5
TOTAL VOTES	6	6
ABSTENTIONS (A)	3	1

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1	Vote 2
Renewable Generation Sub-Sector		
ENGIE Energy Marketing NA, Inc.	A	F
Wheelabrator/Macquarie	A	O
Large RG Group Member	F	F
Distributed Generation Sub-Sector		
CLEAResult Consulting, Inc.	A	A
Load Response Sub-Sector		
Veolia Flexible Energy Services NA	O	F
Vermont Energy Investment Corp.	O	F
IN FAVOR (F)	1	4
OPPOSED (O)	2	1
TOTAL VOTES	3	5
ABSTENTIONS (A)	3	1

TRANSMISSION SECTOR

Participant Name	Vote 1	Vote 2
Avangrid (CMP/UI)	F	F
Eversource	F	F
National Grid	F	F
Rhode Island Energy	F	F
VELCO	F	F
Versant Power	F	F
IN FAVOR (F)	6	6
OPPOSED (O)	0	0
TOTAL VOTES	6	6
ABSTENTIONS (A)	0	0

SUPPLIER SECTOR

Participant Name	Vote 1	Vote 2
BP Energy Company	F	F
Brookfield Renewable Trading & Mktg	O	O
Clearway Power Marketing	A	A
Constellation Energy Generation	A	O
Cross-Sound Cable Company	F	F
DTE Energy Trading, Inc.	F	F
Emera Energy Companies	A	A
Gabel Associates, Inc.	O	A
Galt Power, Inc.	F	F
LIPA	A	A
Mercuria Energy America, LLC	A	A
NRG Business Marketing, LLC	A	O
Shell Energy North America (US) LP	O	O
IN FAVOR (F)	4	4
OPPOSED (O)	3	4
TOTAL VOTES	7	8
ABSTENTIONS (A)	6	5

NOVEMBER 12, 2026 PARTICIPANTS COMMITTEE MEETING
ROLL CALL VOTES

END USER SECTOR

Participant Name	Vote 1	Vote 2
Bath Iron Works	F	F
Conn. Office of Consumer Counsel	O	F
Conservation Law Foundation	A	A
Earthjustice	O	F
Elektrisola, Inc.	F	F
Environmental Defense Fund	A	A
Environmental League of Massachusetts	O	F
Fiscal Alliance Foundation	F	A
Garland Manufacturing Co.	F	F
Green Oceans	F	O
Hammond Lumber Co.	F	F
Harvard Dedicated Energy Limited	O	F
High Liner Foods	F	F
Industrial Wind Action Corp.	F	A
Lamson, Jon	A	A
Maine Public Advocate Office	O	O
Mass. Attorney General's Office	O	F
Mass. Dept. of Capital Asset Management	O	O
Moore Company	F	F
NH Office of Consumer Advocate	O	F
Nylon Corporation	F	F
PowerOptions, Inc.	O	F
RI Division of Public Utilities and Carriers	O	F
Saint Anselm College	F	F
Shipyard Brewing Co.	F	F
Z-TECH, LLC	F	F
IN FAVOR (F)	13	18
OPPOSED (O)	10	3
TOTAL VOTES	23	21
ABSTENTIONS (A)	3	5

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1	Vote 2
Ashburnham Municipal Light Plant	F	F
Belmont Municipal Light Dept.	F	F
Block Island Utility District	F	F
Boylston Municipal Light Dept.	F	F
Braintree Electric Light Dept.	F	F
Chester Municipal Light Dept.	F	F
Chicopee Municipal Lighting Plant	F	F
Clear River Electric and Water District	F	F
Concord Municipal Light Plant	F	F
Conn. Municipal Electric Energy Coop.	F	F
Danvers Electric Division	F	F

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote 1	Vote 2
Georgetown Municipal Light Dept.	F	F
Groton Electric Light Dept.	F	F
Groveland Electric Light Dept.	F	F
Hingham Municipal Lighting Plant	F	F
Holden Municipal Light Dept.	F	F
Holyoke Gas & Electric Dept.	F	F
Hudson Light and Power Dept.	F	F
Hull Municipal Lighting Plant	F	F
Ipswich Municipal Light Dept.	F	F
Littleton (MA) Electric Light Dept.	F	F
Mansfield Municipal Electric Dept.	F	F
Marblehead Municipal Light Dept.	F	F
Mass. Municipal Wholesale Electric Co.	F	F
Mass. Bay Transportation Authority	F	F
MDC – The (CT) Metropolitan District	F	F
Merrimac Municipal Light Dept.	F	F
Midcoast Regional Redevelopment Authority	F	F
Middleborough Gas and Elec. Dept.	F	F
Middleton Municipal Electric Dept.	F	F
New Hampshire Electric Cooperative	F	F
North Attleborough Electric Dept.	F	F
Norwood Municipal Light Dept.	F	F
Paxton Municipal Light Dept.	F	F
Peabody Municipal Light Plant	F	F
Princeton Municipal Light Dept.	F	F
Reading Municipal Light Dept.	F	F
Rowley Municipal Lighting Plant	F	F
Russell Municipal Light Dept.	F	F
Shrewsbury Electric & Cable Operations	F	F
South Hadley Electric Light Dept.	F	F
Sterling Municipal Electric Light Dept.	F	F
Stowe (VT) Electric Dept.	F	F
Taunton Municipal Lighting Plant	F	F
Templeton Municipal Lighting Plant	F	F
Vermont Public Power Supply Authority	F	F
Village of Hyde Park (VT) Electric Dept.	F	F
Wakefield Municipal Gas and Light Dept.	F	F
Wallingford (CT), Town of	F	F
Wellesley Municipal Light Plant	F	F
West Boylston Municipal Lighting Plant	F	F
Westfield Gas & Electric Light Dept.	F	F
IN FAVOR (F)	52	52
OPPOSED (O)	0	0
TOTAL VOTES	52	52
ABSTENTIONS (A)	0	0

CONSENT AGENDA

Reliability Committee (RC)

*From the previously-circulated notice of RC actions at the **November 17, 2026 RC Meeting**, dated November 17, 2026.*[1]

1. Revisions to OP-2 Appendix C (Biennial Review)

Support revisions to Appendix C (Equipment Maintenance Request Form) to ISO New England Operating Procedure (OP) No. 2 (Maintenance of Communications, Computers, Metering, and Computer Support Equipment),[2] as recommended by the RC at its November 17, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously.

2. Revisions to OP-13 (to enable future compliance with NERC EOP-011 and NPCC Directory #2 requirements)

Support revisions to OP-13 (Standards for Voltage Reduction and Load Shedding Capability),[3] as recommended by the RC at its November 17, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously.

3. Revisions to OP-14 Appendix I (Periodic Review)

Support revisions to Appendix I (Continuous Storage Facility (CSF) Operators Guide) to OP-14 (Technical Requirements for Assets and Resources),[4] as recommended by the RC at its November 17, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously.

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[1] RC Notices of Actions are posted on the ISO-NE website at: https://www.iso-ne.com/committees/reliability/reliability-committee/?document-type=Committee%20Actions.

[2] The Appendix C changes include revisions that (i) rename Part One to Equipment Maintenance Request Form; (ii) remove Part Two for consistency with the OP-2 process; and (iii) make minor administrative changes.

[3] The OP-13 changes include revisions to: (i) add requirements for load shedding plans, manual load shedding, and Underfrequency Load Shedding to address compliance with NERC EOP-011 and NPCC Directory #2; (ii) add a new Appendix D to enable submission of load shedding plans; and (iii) clarify and update references.

[4] The OP-14 Appendix I changes include revisions to: (i) update the title of OP-14; (ii) clarify language with respect to CSF data; (iii) remove Section 4; and (iv) retire former Attachments A (CSF Configuration Diagrams) and B (CSF Static Data Information Form).

Summary of ISO New England Board and Committee Meetings

December 3, 2026 Participants Committee Meeting

Since the last update, the Audit and Finance Committee, the Compensation and Human Resources Committee, the Markets Committee, the Nominating and Governance Committee, and the System Planning and Reliability Committee each met on November 11. The Board of Directors met on November 10 and 11. All of the meetings were held in Boston, Massachusetts.

The Audit and Finance Committee reviewed a report on current budget performance, along with an update on interest rates and an update on the new building project, which remains on schedule and budget. The Committee also discussed funding for the strategic plan within the constraints of the budget process. The Committee reviewed and approved the unaudited financial statements for the third quarter after receiving a report on the related disclosure control process. Next, the Committee met with representatives of KPMG, the Company's external auditors, to discuss the scope and preliminary results of the 2026 System and Organization Controls Report and resulting unqualified audit opinion. KPMG also provided an overview of work plans and timing for the financial statements audit. The Committee met with KPMG in executive session to ensure that the auditors had the opportunity to make any necessary reports without management present. Following that session, the Committee received a report on internal audit activities and the department's work across the areas of compliance readiness, operational reliability, market transformation assurance, and process resilience.

The Compensation and Human Resources Committee discussed key dates and deliverables for 2027 goal setting and the corporate performance review for 2026. The Committee also received a report on employee compliance with the Code of Conduct following the annual collection of certificates. Next, the Committee discussed opportunities for employee outreach. During an executive session, the Committee discussed CEO, executive, and board director compensation benchmarking reviews prepared by Mercer, the Company's compensation consultant, and succession planning issues.

The Markets Committee was provided with a summary of market performance for the 2026 summer season from the internal and external market monitors, including wholesale electricity costs and energy prices. The Committee also received an update on the Capacity Auction Reforms project, including stakeholder feedback and potential design updates.

The Nominating and Governance Committee discussed possible site visits and potential guest speakers for the Board in 2027 as part of the Board's continuing education program. The Committee then discussed timing changes to Board meeting schedules, and the ongoing consideration of the form of Board oversight of the Company's artificial intelligence activities. The Committee also received an update on strategic planning activities.

The System Planning and Reliability Committee reviewed the winter operations outlook for the 2026/2027 season. The Committee also reviewed key operations and planning metrics, as well as reliability standards

compliance. The Committee received updates on various operations and planning activities, including longer-term transmission planning, compliance with the Federal Energy Regulatory Commission's Order No. 2023, development of the Asset Condition Reviewer function, and winter preparedness. The Committee was provided with a preview of major system planning activities through the end of 2026 and early 2027. Next, the Committee held a more in-depth discussion of the Asset Condition Reviewer project, and prepared for the upcoming meetings with the NEPOOL sectors.

The Board of Directors met to prepare for its annual open meeting, and held a strategic planning session. The Board then conducted the open meeting and a debrief session following the open meeting. The next day, the Board reconvened and received a report from management, including updates on activities related to FERC, the federal executive and legislative branches, and the New England states. The Board also discussed updates to its communications policy regarding the use of secure applications for emergency communications. The Board received a report from the Chief Financial Officer and reports from the standing committees. Lastly, the Board prepared for its upcoming meetings with the NEPOOL sectors, and held an executive session.

NEW ENGLAND POWER POOL
PARTICIPANTS COMMITTEE MEETING

December 3, 2026

RESOLUTION REGARDING ELECTION OF OFFICERS FOR 2027

WHEREAS, Section 4.6 of the Participants Committee Bylaws sets forth procedures for the nomination and election of a Chair and Vice-Chairs of the Participants Committee; and

WHEREAS, pursuant to those procedures the individuals indentified in the following resolution were nominated and elected for 2027 to the offices of Chair and Vice-Chair, as set forth opposite their names; and

WHEREAS Section 7.1 of the Second Restated NEPOOL Agreement provides that officers be elected at the Annual Meeting of the Participants Committee.

NOW, THEREFORE, IT IS

RESOLVED, that the Participants Committee hereby adopts and ratifies the results of the election held in accordance with Section 4.6 of the Bylaws and elects the following individuals for 2027 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	Aleks Mitreski
Vice-Chair	Jackie Bihrle
Vice-Chair	Sarah Bresolin
Vice-Chair	Dave Cavanaugh
Vice-Chair	Steve Kirk
Vice-Chair	Dave Norman
Secretary	Sebastian Lombardi
Assistant Secretary	Pat Gerity

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Tom Kaslow, Chair, NEPOOL Budget & Finance Subcommittee
Rosendo Garza, NEPOOL Counsel

DATE: November 24, 2026

RE: Estimated Budget for 2027 Participant Expenses

At its December 3 meeting, the Participants Committee will be asked to approve the estimated NEPOOL expense budget for 2027 (2027 Budget), included as Attachment A. The proposed 2027 Budget estimates are compared to both the 2026 estimates approved by the Participants Committee at the 2025 annual meeting and the current forecasts for 2026. An estimated projection of a Participant's share of the 2027 Budget expenses, including a comparison to 2022 per-Participant expense shares, is included as Attachment B.[1]

Consistent with prior years' practice, NEPOOL Counsel, the GIS Administrator, the ISO, and NEPOOL's Independent Financial Advisor collaborated to develop the recommended 2027 Budget. The Budget & Finance Subcommittee discussed the proposed 2027 Budget at its November 20 meeting. The discussion included questions regarding the GIS and credit insurance premium line items and revenue, as well as the 2026 current forecast for counsel fees.[2] No Subcommittee member expressed opposition to the proposed 2027 Budget.

Accordingly, the following form of resolution may be used for action on the 2027 Budget:

> RESOLVED, that the Participants Committee adopts the estimated NEPOOL expense budget for 2027 as presented at this meeting.

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[1] Expressed on an annualized basis over this five-year period, estimated shares would increase by approximately 0.3% for Generation and Supplier Sector voting members other than Related Person Suppliers, and Large Renewable Generation Resource Providers; increase by approximately 1.8% for Publicly Owned Entity Sector members; and decrease by approximately 1.5% for Transmission Sector voting members.

[2] Additional context and clarification in response to those questions was provided to those Participant representatives raising the questions.

ESTIMATED 2027 NEPOOL BUDGET COMPARED TO
2026 NEPOOL BUDGET AND 2026 PROJECTED ACTUAL EXPENSES

Line Items	2026 Approved Budget	2027 Proposed Budget	2026 Current Forecast
NEPOOL Counsel Fees (1) (2)	$4,500,000	$4,650,000	$4,600,000
NEPOOL Counsel Disbursements (1)	$30,000	$30,000	$30,000
Independent Financial Advisor Fees and Disbursements (3)	$48,000	$48,000	$47,000
Committee Meeting Expenses (1) (2)	$1,050,000	$1,050,000	$1,060,000
Generation Information System (5)	$1,347,237	$1,641,111	$1,456,540
Credit Insurance Premium (4)	$561,700	$680,000	$561,700
NEPOOL Audit Management Subcommittee ("NAMS") Consultant (6)	$0	$0	$0
SUBTOTAL EXPENSES	$7,536,937	$8,099,111	$7,755,240
Revenue			
NEPOOL Membership Fees (4)	($2,500,000)	($2,600,000)	($2,493,200)
Generation Information System (5) (7)	($1,347,237)	($1,641,111)	($1,456,540)
Credit Insurance Premium (4) (8)	($561,700)	($680,000)	($561,700)
TOTAL REVENUE	($4,408,937)	($4,921,111)	($4,511,440)
TOTAL NEPOOL EXPENSES	$3,128,000	$3,178,000	$3,243,800

Notes

(1) Day Pitney LLP, NEPOOL Counsel, provided the 2027 proposed estimate.

(2) The 2026 Current Forecast reflects the level of activity associated with the region's demanding work plan.

(3) Michael M. Mackles, NEPOOL's Independent Financial Advisor, provided the 2027 proposed estimate.

(4) ISO New England Inc. provided the 2027 proposed estimate.

(5) Based on fee arrangement set forth in the Extension of and First Amendment to Amended and Restated Generation Information System Administration Agreement, pursuant to which the projected annualized fixed fee for 2027 is $1,641,111.92. This amount includes $15,000 for ISO-NE's administrative GIS-related costs. The estimate assumes that NEPOOL will remain in the 180,000–189,999 tier of total Account Holders and Generators for the first four months of the year (January through April), increase to the 190,000–199,999 tier for the following four months (May through August), and then increase to the 200,000–209,999 tier for the final four months of the year (September through December).

The 2026 Current Forecast is higher than the 2026 Approved Budget because the number of Account Holders and Generators increased more rapidly than projected and a GIS-related change approved in 2026 was not anticipated in the original budget.

(6) If NEPOOL determines that an audit should be performed in 2027, then funding for that audit will be addressed separately.

(7) GIS costs are paid by "GIS Participants" pursuant to the Allocation of Costs Related to Generation Information System, as approved by the NEPOOL Participants Committee on June 21, 2001 and amended on May 6, 2016.

(8) Credit insurance premiums are paid by Qualifying Market Participants in accordance with the methodology set forth in Section IX of the ISO New England Financial Assurance Policy.

ESTIMATED BREAKDOWN OF PROJECTED 2027 NEPOOL EXPENSE BUDGET AMONG SECTOR MEMBERS

(2022 figures as projected and budgeted at the 2021 Annual Meeting)

CALCULATION OF COSTS TO BE ALLOCATED TO NEPOOL SECTORS			
		2027	**2022**
A.	Total Projected NEPOOL Expenses (not including costs associated with GIS, credit insurance premium, which are funded separately)	**5,778,000**	**5,000,000**
B.	Projected NEPOOL Membership Fees	**2,500,000**	**2,140,000**
C.	Total Projected NEPOOL Expenses to be Funded Through Non-Hourly Charges (A – B)	**3,278,000**	**2,860,000**
D.	Projected Amount to be paid by all Market Participant End Users (based on highest hourly load in any month in preceding calendar year) (figure used here for 2027 is based on 2026 peak loads of MPEU members)	**26,131**	**41,179**
E.	Total Amount paid by all Load Response, Distributed Generation, and Small Renewable Generation Resource Providers in AR Sector (figure used here for 2027 is estimated amount based on 2026 membership data)	**105,587**	**77,462**
F.	[Reserved]	**0**	**0**
G.	Large Renewable Generation Sub-Sector Share (C-(D+E)) x RG%	**314,628**	**274,136**
H.	Total Amount to be Allocated among Transmission, Generation, Supplier and Publicly Owned Entity Sectors (“Remaining Sectors”) (C – (D+E+G))	**2,831,654**	**2,467,223**

CALCULATION OF SECTOR ALLOCATIONS			
		2027	**2022**
I.	Amount to be allocated to each of the Remaining Sectors (H ÷ 4)	**707,913**	**616,806**
J.	Total Amount paid by Related Person Suppliers (3 voting members) (I ÷ s_y) x rps_y	**9,254**	**8,939**
K.	Aggregate Share to be paid by Generation Sector/Supplier Sector/ Large Renewable Generation Resource Providers ((I x 2) + G – J)	**1,721,201**	**1,498,808**
L.	[Reserved]	**0**	**0**
M.	Remainder of Aggregate Share to be paid, on a per member basis, by voting members in the Generation Sector, Supplier Sector (excluding Related Person Suppliers), and Large Renewable Generation Resource Providers (K ÷ (g_y + (s_y - rps_y) + lrg_y))	**9,835**	**9,486**
N.	Transmission Sector Share per full voting member (I÷ t_y)	**117,986**	**123,361**
O.	[Reserved]	**0**	**0**
P.	Publicly Owned Entity Sector Member Share (assuming equal sharing of Publicly Owned Entity Sector Share Participant Expense among voting Sector members)[i] (I ÷ poe_y)	**11,799**	**10,224**

ANNUAL VARIABLES			
		2027	**2022**
s_y	# Supplier Sector voting members	**151**	**129**
rps_y	# Supplier Sector Related Person Suppliers	**2**	**2**
g_y	# Generation Sector voting members	**12**	**11**
lrg_y	# AR Sector Large Renewable Generation Resource Providers	**12**	**11**
RG%	Lesser of (lrg_y*2%) or 10%	**10%**	**10%**
t_y	# Transmission Sector voting members	**6**	**5**
poe_y	# Publicly Owned Entity voting members	**60**	**59**

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Rosendo Garza, NEPOOL Counsel

DATE: November 24, 2026

RE: Proposed Billing Policy Revisions in Response to FERC Show Cause Order to Address Erroneous or Improper Payments and Participant Errors

At the December 3, 2026 Participants Committee meeting, you will be asked to vote on the ISO's proposed revisions to the ISO New England Billing Policy (Billing Policy) to address erroneous or improper payments and charges in the New England Markets and expand the types of errors eligible for correction through the Requested Billing Adjustment (RBA) process. The revisions respond to FERC's September 10, 2026 order[1] directing the ISO to submit a compliance filing with the Billing Policy revisions that the ISO had described in its response[2] to the Commission's underlying March 2026 Show Cause Order.[3] The ISO must submit its compliance filing by January 8, 2027.

Included with this memorandum are the following supporting materials:

- Attachment A: ISO-NE's Redlined Tariff Sheets
- Attachment B: ISO-NE's November 20, 2026 Presentation

OVERVIEW OF BILLING POLICY CHANGES

The ISO proposes two principal changes to the Billing Policy in response to FERC's September 10 Order.

First, the proposed revisions to Section 1.4 would allow the ISO to accept and distribute refunds of payments a Covered Entity erroneously or improperly received in the New England Markets, as well as payments for charges erroneously or improperly not assessed in those markets. To the extent practical, the ISO would process refunds within the existing Market Rule 1 resettlement timelines. For refunds processed after those timelines, amounts provided to the ISO would include interest at FERC's standard rate. Amounts received would be allocated under the cost allocation provisions that would otherwise apply, using the best available data at the time of allocation. A corresponding revision to Section 2.2 would specify that these resettlements are included in the monthly Statement for Non-Hourly Charges.

[1] *ISO New England Inc.*, 196 FERC ¶ 61,185 (2026).

[2] Answer of ISO New England Inc., Docket No. EL26-45-000 (May 8, 2026).

[3] *ISO New England Inc.*, 194 FERC ¶ 61,187 (2026).

Second, the proposed revision to Section 6.1 would remove language limiting the use of the RBA process to billing adjustments to correct for errors the ISO caused, allowing that process to address Participant errors that otherwise satisfy the RBA requirements. The existing RBA procedures and deadlines would otherwise remain unchanged. As is the case under the existing Tariff, the revision would not permit corrections that require assuming a different system commitment or dispatch than actually occurred.

BUDGET & FINANCE SUBCOMMITTEE CONSIDERATION

The ISO presented its proposal at two Budget & Finance (B&F) Subcommittee meetings. At the October meeting, the ISO introduced the proposal and addressed stakeholder questions. At the November meeting, the ISO presented the proposed redlines and provided examples in response to stakeholder feedback. No B&F Subcommittee member present at either meeting expressed opposition to the proposed changes.

The following form of resolution may be used for Participants Committee action:

> RESOLVED, that the Participants Committee supports the revisions to the ISO New England Billing Policy to establish a mechanism to accept and distribute refunds of erroneous or improper payments, as well as payments for charges erroneously or improperly not assessed, and to expand the Requested Billing Adjustment process to address Participant errors, as reflected in the materials circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

EXHIBIT ID

ISO NEW ENGLAND BILLING POLICY

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SECTION 2 – TIMING AND CONTENT OF STATEMENTS

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SECTION 5 – SHORTFALL FUNDING ARRANGEMENT; PAYMENT DEFAULT SHORTFALL FUND

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SECTION 7 – WEEKLY BILLING PRINCIPLES FOR NON-HOURLY CHARGES

EXHIBIT ID ISO NEW ENGLAND BILLING POLICY

SECTION 1 – OVERVIEW

Section 1.1 – Scope. The objective of this ISO New England Billing Policy is to define the billing and payment procedures to be utilized in administering charges and payments due under the Transmission, Markets and Services Tariff and the ISO Participants Agreement, in each case as amended, modified, supplemented and restated from time to time (collectively, the "Governing Documents"). Capitalized terms used but not defined in the ISO New England Billing Policy shall have the meanings specified in Section I. The ISO New England Billing Policy applies to the ISO, the Market Participants, Non-Market Participant Transmission Customers, PTOs, and Market Participants that transact only in the FTR Auction ("FTR-Only Customers") (referred to herein collectively as the "Covered Entities" and individually as a "Covered Entity") for billing and payments procedures for amounts due under the Governing Documents, including without limitation those procedures related to the New England Markets. As reflected and specified in Section 3 hereof, the ISO's obligation to make Payments (as defined below) is contingent on its receipt of sufficient aggregate Charges (as defined below) (or in cases of defaults in Covered Entities' payments of Charges, on the ISO's drawdowns under the ISO New England Financial Assurance Policy or recovery using the mechanisms specified in Section 3, 4 and 5 hereof).

Section 1.2 – Financial Transaction Conventions. The following conventions have been adopted in defining sums of money to be paid or received under the ISO New England Billing Policy:

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

b) The term "Payment" refers to a sum of money due to a Covered Entity from the ISO. Amounts due to and from the ISO include amounts collected and paid by the ISO as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

charges and payments described in this clause (iii) being referred to collectively as "Transmission Charges"). There are two major steps in the billing process:

a) *Statement Issuance*. The ISO will issue an Invoice or Remittance Advice showing the net amounts due from or owed to a Covered Entity. This Statement is determined from the preliminary statements of the New England Markets, applicable the ISO Charges and/or Transmission Charges due under the Governing Documents (including amounts due under the ISO New England Financial Assurance Policy), as well as applicable adjustments. Prior to January 1 of any calendar year, the ISO will post or make available a list of the dates in the new calendar year on which Statements will be issued, due and paid. Billing and payment holidays will be the same as the ISO's settlement holidays, as listed on the ISO's website from time to time.

b) *Electronic Funds Transfer ("EFT").* EFTs related to Invoices and Remittance Advices are performed in a two-step process, as described below, in which all Invoices are paid first and all Remittance Advices are paid later.

Section 1.4 – Special Billings and Refund Mechanism.

a) In addition to the regular billing process described above, the ISO will issue special, extraordinary Statements as and when required under the Governing Documents or in order to adjust for special circumstances. Such Statements shall be payable in accordance with the instructions set forth therein.

b) Refund Mechanism – The ISO may accept for the purpose of effectuating refunds: (1) the return of payments from Covered Entities that were erroneously or improperly received in the New England Markets; or (2) the payment of charges from Covered Entities that were erroneously or improperly not assessed in the New England Markets. To the extent practical, the ISO shall process such refunds within the timelines for the resettlements determined in accordance with the procedures set forth in Market Rule 1.

If resettlements effectuating refunds pursuant to this section are not processed until after the timelines for the resettlements determined in accordance with the procedures set forth in Market Rule 1, monies provided to the ISO shall include interest on such amounts calculated at the Commission's standard rate, set forth in 18 C.F.R. Section 35.19. The ISO shall allocate refunds made pursuant to this section in accordance with the cost allocation provisions of the Governing Documents that would otherwise apply using the best available data at the time the allocation takes place.

Section 1.5 – Conflicts with Governing Documents. Except as set forth herein, to the extent any provision hereof conflicts with any provision of any Governing Document, the provision in the Governing Document shall govern.

SECTION 2 - TIMING AND CONTENT OF STATEMENTS.

Section 2.1 – Statements for Hourly Charges. On each Monday and each Wednesday or on the following Business Day if such Monday or Wednesday is not a Business Day, the ISO shall provide electronically to each Covered Entity a Statement showing all complete-day settlement amounts for each of the Hourly Charges incurred and not reflected on a previously issued Statement. Each such Statement will cover only days with complete settled data. Accordingly, some Statements may have fewer days of settled data for certain Hourly Charges if fewer days have been settled for those Hourly Charges on the morning of the day that such Statements are issued; a following Statement may have more days of settled data for those Hourly Charges when it becomes possible to catch up on the settled data. Statements will include contiguous month-to-month hourly market billing data and will have separate line items for any hourly market data that may cross calendar months. For example, if a Statement's billing period includes May 30 through June 2, and all of those days are fully settled, the June 8 Statement would have one line item for the period May 30 to May 31 and one line item for the period June 1 to June 2. The Job Aid on the ISO web site will be updated weekly for any information necessary to be distributed through that medium.

Section 2.2 – Monthly Statements for Non-Hourly Charges. The first Statement issued on a Monday after the ninth of a calendar month will include both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month (hereinafter sometimes referred to as a "Monthly Statement"). Resettlements determined in

accordance with the procedures set forth in Market Rule 1 and Section 1.4(b) of the Billing Policy will be included in the monthly Statement for Non-Hourly Charges.

Section 2.3 – Statements for Weekly Billing Non-Hourly Charges. The ISO shall implement any weekly billing arrangements for Non-Hourly Charges effected under the ISO New England Financial Assurance Policy in accordance therewith and with the procedures set forth in Section 7 below.

Section 2.4 – Contents of Statements. Each Statement for Hourly and Non-Hourly Charges will include all of the following line items that are applicable to the Covered Entity receiving such Statement for the period to which such Statement relates:

a) *Invoice or Remittance Advice Amount*. The net amount of all Charges and Payments owed by or due to a Covered Entity for the relevant Statement. The ISO shall issue an Invoice where the Covered Entity owes monies. The ISO shall issue a Remittance Advice where the Covered Entity is owed monies.

b) *OATT Charges and Payments.* The Charges owed by and the Payments owed to the Covered Entity under the OATT *other than* Transmission Charges, which are billed separately under Section 2.5 below.

c) *ISO Self-Funding Charges.* The Charges owed by the Covered Entity under Section IV of the Transmission, Markets and Services Tariff, categorized by the section or schedule under which such Charges arise.

d) *Markets Charges and Payments.* The Hourly Charges owed by and the Payments for Hourly Charges owed to the Covered Entity as a result of transactions in each of the New England Markets administered by the ISO under Section III of the Transmission, Markets and Services Tariff.

e) *Monthly Forward Capacity Market Charges and Payments.* The Non-Hourly Charges owed by and the Payments for Non-Hourly Charges owed to the Covered Entity as a result of Capacity Performance Payments, System-Backed Export Charges, and other transactions in the Forward Capacity Market.

f) *Participant Expenses*. As defined in the Participants Agreement, the Covered Entity's share of costs and expenses that are incurred pursuant to authorization of the Participants Committee and are not considered costs and expenses of ISO.

g) [Reserved for Future Use]

h) *Other Amounts due under the Participants Agreement.* The Charges owed by or the Payments owed to the Covered Entity under the Participants Agreement to the extent that those amounts are not included in items (b)-(g) above.

i) *Other Non-Hourly Charges, Payments or Adjustments*. Any other Non-Hourly Charges, Payments for Non-Hourly Charges, or adjustments owed by or to the Covered Entity that are not included in items (b)-(h) above. These items may be due to retroactive billing adjustments, late payment fees, penalties or other items collectible under the Governing Documents.

j) *Billing Periods*. The billing period (from and to dates) covered for each line item on the Statement. The billing periods for the various line items are not necessarily the same because of differences in timing of settlements and because of retroactive adjustments.

k) *Payment Due Date and Time.* If the Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO.

l) *Wire Transfer Instructions*. Details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which ISO Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for ISO Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Arrangement, that Covered Entity shall be required to pay the amount of such draw, plus any interest accrued thereon and premium or other fees or expenses with respect thereto.

Section 5.5 -Payment Default Shortfall Fund Account. Funds collected as Market Participant contributions to the Payment Default Shortfall Fund shall be deposited by the ISO into a segregated interest-bearing account.

SECTION 6 -BILLING DISPUTE PROCEDURES.

Section 6.1 -Requested Billing Adjustments Eligible for Resolution under Billing Dispute Procedures. Any Covered Entity may dispute the amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice (a "Disputed Amount"). Such party (a "Disputing Party") shall seek to recover such Disputed Amount, including accrued interest, pursuant to this Section 6, by first submitting a request for billing adjustment to the ISO (a "Requested Billing Adjustment" or "RBA") in accordance with the procedures provided in this Section 6. A Disputing Party may seek resolution of a Requested Billing Adjustment under this Section 6 concerning any Disputed Amount resulting from the determination of a market clearing price or Transmission, Markets and Services Tariff rate by the ISO that allegedly either violates or is otherwise inconsistent with the Transmission, Markets and Services Tariff, or results from error ~~by the ISO~~, and provided that a request for a correction of a Meter Data Error shall not be considered a Requested Billing Adjustment for purposes of the ISO New England Billing Policy, and requests for corrections of Meter Data Errors will be handled exclusively through the procedures set out in Market Rule 1. Notwithstanding the foregoing, a Requested Billing Adjustment must involve a requested change in an amount owed or believed to be owed in a Remittance Advice that is not covered by another alternative dispute resolution procedure under the Transmission, Markets and Services Tariff. Furthermore, a Requested Billing Adjustment must not involve Disputed Amounts paid on an Invoice for Non-Hourly Charges pursuant to the ISO New England Financial Assurance Policy, provided, however, that this provision shall not preclude a Disputing Party from submitting a Requested Billing Adjustment for a Disputed Amount on a fully paid monthly Invoice for Non-Hourly Charges which has been paid pursuant to an Invoice for Non-Hourly Charges in that month.

NEPOOL PARTICIPANTS COMMITTEE
DEC 3, 2026 MEETING, AGENDA ITEM #9
Attachment B

Erroneous or Improper Payment Revisions: Show Cause Order EL26-45 Compliance

Proposed Billing Policy revisions to address "erroneous or improper payment" concerns of FERC's Show Cause Order

Ashley Gagnon

SENIOR REGULATORY COUNSEL



Erroneous or Improper Payment Revisions

Proposed Effective Date: 60 days after compliance filing

- At the October Budget and Finance Subcommittee (BFS) meeting, the ISO proposed revisions to the Billing Policy to comply with the Federal Energy Regulatory Commission's (FERC, the Commission) order in Docket EL26-45 (Order) directing the ISO to submit a compliance filing by January 8, 2027, with Billing Policy revisions described in the ISO's response to the Commission's underlying March 2026 Show Cause Order:
  - Add a mechanism to enable the ISO to accept and distribute erroneous or improper payments received by Market Participants
  - Eliminate RBA language limiting process to ISO errors
- Today's discussion will focus on the proposed Billing Policy redlines and address stakeholder feedback received at the October BFS

PROPOSAL SUMMARY

Erroneous or Improper Payment Refund Mechanism

Proposal

- The provision would enable the ISO to accept payments that were erroneously or improperly received in the New England markets for the purpose of effectuating refunds or the payment of charges from Covered Entities that were erroneously or improperly not assessed
  - Added language clarifies that the refund mechanism applies to the situation where a Covered Entity seeks to remedy not being assessed a charge due to error
- To the extent practical, the ISO will process such refunds within the timelines for the resettlements described in Market Rule 1. This includes the Data Reconciliation Process and Meter Data Error process
  - If resettlements effectuating refunds cannot be processed until after Market Rule 1 resettlement processes, money provided to the ISO pursuant to the refund mechanism will include interest at the Commission's standard rate (set forth in 18 C.F.R. Section 35.19)
- The ISO will allocate refunds in accordance with the cost allocation provisions of the Governing Documents that would otherwise apply using the best available data at the time the allocation takes place

Introduced
October
PPS Meeting

Expand Types of Errors ISO Can Correct Under RBA Process

Proposal

- Section 6 of the Billing Policy allows Participants who wish to dispute items on their Statements to submit an RBA within three months of the date of the invoice containing the disputed amount
- The RBA provision has generally been read to limit the use of the RBA process to the correction of errors caused by the ISO
- The ISO proposes to remove this limitation to clarify that the RBA process can be used to correct errors caused by Participants and not just the ISO
  - This change will not permit the correction of errors that could not be corrected if found within the Data Reconciliation Process timelines (*e.g.*, it would not permit the correction of an error that could be corrected only by assuming the system was committed or dispatched differently from the actual commitment or dispatch)

OCTOBER FOLLOW UPS

Process for RBAs Under Expanded Mechanism

- The change will provide the ISO with the flexibility to address errors within the RBA process that cannot be causally linked to an action on the part of the ISO, *i.e.*, Participant error
  - The Commission found this proposal would address concerns in the Show Cause Order by allowing the ISO to correct a greater range of errors without need for Tariff waivers from the Commission
- The ISO is not proposing any other changes to the existing RBA process
  - RBAs submitted under the expanded provision will follow the current process set forth in Section 6.0 of the Billing Policy
- As with RBAs under the current process (which have been relatively limited)—determinations will be made on a case-by-case basis based on the specific facts of each case

Participant Error RBA Examples

- To help provide a general sense of types of Participant error that may and may not be eligible for correction under the expanded RBA process, the ISO is providing two high-level examples for illustrative purposes only
- Example of Participant error that may have been eligible for correction under expanded RBA process:
  - Participant incorrectly enters information associated with a Forward Reserve Market bilateral transaction
    - Past instances where this has taken place and the ISO lacked a means of addressing the error once discovered
- Example of Participant error that would not be eligible for correction under expanded RBA process:
  - Participant inputs incorrect operating parameter information that is used to clear the market
    - This falls under the Tariff Section III.3.6.2 prohibition of correcting errors that could be corrected only by assuming the system was committed or dispatched differently from the actual commitment or dispatch

BILLING POLICY REDLINES

Summary of Proposed Tariff Changes

Billing Policy Section	Description of Change	Reason for Change
Section 1.4 – Special Billings	Add refund mechanism	Allows the ISO to accept and refund erroneous or improper payments/payments for charges not assessed by Market Participants
Section 2.2 – Monthly Statement for Non-Hourly Charges	Add new Section 1.4(b) to description of Monthly Statement of Non-Hourly Charges	Specifies which Statement resettlements pursuant to new Section 1.4(b) will appear
Section 6.1 – Requested Billing Adjustments Eligible for Resolution under Billing Dispute Procedures	Remove language limiting RBA process to ISO Error	Expands types of errors that can be addressed through the RBA Process

Redlines – Section 1.4 Special Billings

Section 1.4 – Special Billings and Refund Mechanism.

a) Special Billings - In addition to the regular billing process described above, the ISO will issue special, extraordinary Statements as and when required under the Governing Documents or in order to adjust for special circumstances. Such Statements shall be payable in accordance with the instructions set forth therein.

b) Refund Mechanism – The ISO may accept for the purpose of effectuating refunds: (1) the return of payments from Covered Entities that were erroneously or improperly received in the New England Markets; or (2) the payment of charges from Covered Entities that were erroneously or improperly not assessed in the New England Markets. To the extent practical, the ISO shall process such refunds within the timelines for the resettlements determined in accordance with the procedures set forth in Market Rule 1.

If resettlements effectuating refunds pursuant to this section are not processed until after the timelines for the resettlements determined in accordance with the procedures set forth in Market Rule 1, monies provided to the ISO shall include interest on such amounts calculated at the Commission's standard rate, set forth in 18 C.F.R. Section 35.19. The ISO shall allocate refunds made pursuant to this section in accordance with the cost allocation provisions of the Governing Documents that would otherwise apply using the best available data at the time the allocation takes place.

Redlines – Section 2.2 Monthly Statement for Non-Hourly Charges

Section 2.2 – Monthly Statements for Non-Hourly Charges. The first Statement issued on a Monday after the ninth of a calendar month will include both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month (hereinafter sometimes referred to as a "Monthly Statement"). Resettlements determined in accordance with the procedures set forth in Market Rule 1 and Section 1.4(b) of the Billing Policy will be included in the monthly Statement for Non-Hourly Charges.

Redlines – Section 6.1 Requested Billing Adjustments Eligible for Resolution Under Billing Dispute Procedures

Section 6.1 -Requested Billing Adjustments Eligible for Resolution under Billing Dispute Procedures. Any Covered Entity may dispute the amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice (a "Disputed Amount"). Such party (a "Disputing Party") shall seek to recover such Disputed Amount, including accrued interest, pursuant to this Section 6, by first submitting a request for billing adjustment to the ISO (a "Requested Billing Adjustment" or "RBA") in accordance with the procedures provided in this Section 6. A Disputing Party may seek resolution of a Requested Billing Adjustment under this Section 6 concerning any Disputed Amount resulting from the determination of a market clearing price or Transmission, Markets and Services Tariff rate by the ISO that allegedly either violates or is otherwise inconsistent with the Transmission, Markets and Services Tariff, or results from error ~~by the ISO~~, and provided that a request for a correction of a Meter Data Error shall not be considered a Requested Billing Adjustment for purposes of the ISO New England Billing Policy, and requests for corrections of Meter Data Errors will be handled exclusively through the procedures set out in Market Rule 1 . . .

CONCLUSION AND NEXT STEPS

Conclusion

- Changes to the Billing Policy are required to comply with FERC's September 26 Order in EL26-45
- Consistent with the Order, the ISO is proposing two discrete changes to the Billing Policy:
  - Add a mechanism to enable the ISO to accept and distribute erroneous or improper payments received by Market Participants or the payment of charges from Covered Entities that were erroneously or improperly not assessed
  - Eliminate RBA language limiting process to ISO errors
- A compliance filing is required by January 8, 2027
- The proposed effective date will be 60 days after filing

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Budget and Finance Subcommittee October 9, 2026	Introduce proposed Billing Policy design change and proposed redline summary
Budget and Finance Subcommittee November 20, 2026	Present Billing Policy redlines
Participants Committee December 3, 2026	Vote

Questions



About the Presenter

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M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: NEPOOL Counsel

DATE: November 24, 2026

RE: Capacity Auction Reforms Seasonal/Accreditation (CAR-SA) Proposal

At its December 3, 2026 Annual Meeting, the Participants Committee will be asked to consider and vote to support a package of revisions to the ISO New England Inc. Tariff (Tariff) that would transition the prompt annual capacity market to a seasonal structure and revise capacity accreditation methodologies as part of the ISO's Capacity Auction Reforms (CAR) initiative (CAR-SA Proposal). This memorandum provides a high-level overview of the proposal and includes the following attachments:

- Attachment A: Tariff Redlines, as recommended by the Markets Committee[1]
- Attachment B: Tariff Redlines, as recommended by the Reliability Committee
- Attachment C: Tariff Redlines, as recommended by the Transmission Committee
- Attachment D: Tariff Redlines, as reviewed by the Budget & Finance Subcommittee
- Attachment E: Markets Committee Notice of Actions (NOA), dated November 6, 2026
- Attachment F: Reliability Committee NOA, dated November 17, 2026
- Attachment G: Transmission Committee NOA, dated November 19, 2026
- Attachment H: ISO-NE Voting Memorandum, dated October 29, 2026

BACKGROUND

As early as 2022, the ISO identified plans to evaluate a shift to a prompt seasonal capacity market. In late 2025, NEPOOL and the ISO jointly filed the first phase of the CAR initiative, known as CAR-PD, which the Federal Energy Regulatory Commission (FERC) accepted earlier this year.[2] CAR-PD provides for the transition from the Forward Capacity Market to a prompt annual Capacity Market and replaces the existing retirement framework with

[1] Following the Markets Committee meeting, the ISO made additional Tariff revisions in response to stakeholder feedback. The Markets Committee Chair and Vice-Chair determined that those revisions were non-substantive. *See* Memorandum from E. Laine & B. Griffiths to the NEPOOL Markets Committee, Notice of Non-Substantive Changes to Capacity Auction Reforms – Seasonal/Accreditation (CAR-SA) Tariff Package (Nov. 18, 2026), https://www.iso-ne.com/static-assets/documents/100041/2026_11_18_mc_non-substantive_change_car-sa_memo.pdf. The affected Tariff sheets, with those revisions highlighted, are available here. Attachment A contains the Tariff redlines recommended by the Markets Committee, incorporating the non-substantive changes the Chair and Vice-Chair approved, for Participants Committee consideration. It does not separately highlight those changes.

[2] *ISO New England Inc.*, 194 FERC ¶ 61,249 (2026).

a separate deactivation process. In 2026, building on that work, the ISO and regional stakeholders developed the second phase of the CAR initiative, CAR-SA.

HIGH-LEVEL OVERVIEW OF THE CAR-SA PROPOSAL

The ISO's CAR-SA Proposal would establish a prompt seasonal Capacity Market with accreditation reforms. Single-season auctions, one for Summer (May 1–October 31)[3] and one for Winter (November 1–April 30), would be conducted separately. This seasonal construct requires changes to existing Market Rules and business processes, including the timing of activities leading up to and through each auction.[4] The Proposal would establish resource-specific accreditation based on marginal contributions to reliability and introduce a winter gas constraint with related firm-fuel requirements. The Proposal would also phase in the new accreditation framework over three years, with full implementation in the fourth year under what the ISO refers to as the CAR-SA "steady state."

Seasonal Capacity Accreditation

The accreditation reforms would replace the existing Qualified Capacity (QC)-based approach with Seasonal MRI Capacity, a seasonal accreditation value reflecting Marginal Reliability Impact (MRI).[5] Each value would reflect the resource's capability[6] and modeled contribution to system reliability and would generally set the maximum quantity of capacity the resource could offer in each seasonal auction.[7] The ISO would calculate the values using the Resource Adequacy Assessment (RAA) model, which also informs the Net Installed Capacity Requirement and capacity demand curves. The RAA model applies a resource adequacy criterion of no more than one day of expected load loss in ten years. CAR-SA would divide the annual Loss of Load Expectation target of 0.1 days per year equally between summer and winter, assigning 0.05 days to each season.

For resources modeled individually, the RAA model would estimate each resource's contribution to reliability by measuring its effect on expected unserved energy. It would consider characteristics such as Equivalent Forced Outage Rate on Demand (EFORd), energy storage

[3] The first Summer Capacity Commitment Period would run from June 1 through October 31, 2028; subsequent summer periods would begin May 1.

[4] The ISO proposes revised schedules for pre-auction activities and the seasonal auctions. The Proposal would also introduce internal bilateral transactions for capacity, allowing Participants to use ISO settlement systems to settle capacity price hedges agreed upon before the auction.

[5] The proposed definition for MRI is "the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year."

[6] Maximum Capability measures a resource's underlying capability before accounting for its modeled contribution to reliability. For intermittent resources, it is based on Global Maximum Capability, which generally reflects maximum demonstrated hourly performance across seasons. For other resources, it generally reflects capability under season-specific conditions.

[7] CAR-SA includes a methodology for determining the capacity offer MW quantity associated with predictable reductions in resource output at elevated ambient temperatures.

capability, and output profiles. Some resources would not be modeled individually.[8] Instead, their accreditation values would be based on the performance of comparable resource types.

Winter Gas Constraint and Firm-Fuel Requirements

The ISO's winter gas-constraint design would account for limited winter gas availability through a Gas-Constrained Winter Capacity Demand Curve. The curve would reflect the declining incremental reliability value of non-firm gas capacity as more of that capacity is procured. When binding, the constraint could reduce the quantity of non-firm gas capacity procured and the price paid to that capacity. It would not directly reduce resource-specific Seasonal MRI Capacity values.

Gas-fired capacity backed by qualifying firm-fuel arrangements would be exempt from the constraint. For capacity designated as firm through gas contracts, the ISO would require contracts covering December through February that satisfy specified pipeline transportation or liquefied natural gas supply requirements.[9] Resources with dual-fuel capability and qualifying oil storage arrangements could also satisfy the firm-fuel requirements.

Transition Provisions

The CAR-SA Proposal would phase in the new accreditation framework over three years (the Transition). For most resources, seasonal accreditation would blend Seasonal MRI Capacity and Estimated QC.[10] Seasonal MRI Capacity would receive a 25 percent weight in the first year, 50 percent weight in the second year, and 75 percent weight in the third year. Full Seasonal MRI Capacity accreditation would apply in the fourth year. Corresponding adjustments to capacity demand parameters would keep procurement requirements aligned with the capacity values resources are permitted to offer.

Two additional measures would apply during the Transition: (1) for energy storage resources, the ISO would moderate the effect of modeled reliability-event durations on winter storage accreditation, using a 16-hour storage duration as the benchmark, reduced from the previously proposed 24-hour benchmark; and (2) the ISO would temporarily accept a broader range of firm-gas contracts under qualification standards consistent with those that were used in

[8] These include Passive Demand Capacity Resources, Import Capacity Resources, and newly commercial resources not included in the RAA model.

[9] During the three-year transition, the ISO would temporarily relax the firm-gas qualification requirements by also accepting qualifying gas supply contracts meeting North American Energy Standards Board or International Swaps and Derivatives Association firm-service standards. This broader qualification pathway would apply during the 2028–2029, 2029–2030, and 2030–2031 Winter Capacity Commitment Periods.

[10] Estimated QC is calculated by multiplying the resource's Maximum Capability for the relevant seasonal auction by its applicable seasonal ratio of QC to Maximum Capability.

the Inventoried Energy Program (IEP),[11] allowing Market Participants additional time to arrange contracts that satisfy the full CAR-SA requirements.

SUMMARY OF STAKEHOLDER PROCESS

Because the CAR-SA Proposal includes Tariff revisions to the Market Rules, the Open Access Transmission Tariff (OATT), and defined terms in Section I.2.2,[12] the Technical Committees reviewed successive iterations of the CAR-SA Proposal in joint sessions, along with various Participant-sponsored ideas and proposals. Each Committee separately considered the Tariff revisions within its purview. The Budget & Finance Subcommittee met separately to review the Proposal's changes to the Financial Assurance Policy (FAP) and Billing Policy.

Markets Committee Consideration and Action

Following nearly a year of review and discussion, the Markets Committee, at its November 4–5 meeting, considered the Proposal's Tariff revisions under its purview. Specifically, it reviewed revisions to the following Tariff sections, which are provided in Attachment A: (1) Section I.2.2; (2) Section III.1 (excluding Section III.1.5); (3) Section III.3; (4) Section III.10; (5) Section III.15; (6) Section III.A; and (7) Section III.F. The Markets Committee voted two motions to amend the ISO's Proposal, both of which failed, as summarized below. NRG withdrew a separate motion to amend after the ISO agreed to incorporate its concept concerning post-auction publication of resource-level Capacity Supply Obligation information.[13] The Markets Committee recommended Participants Committee support for the Proposal, as revised to incorporate NRG's proposed Tariff language, with 78.59% in favor.

1. *Constellation – Establishing an Alternative Methodology for Ambient Air Offer MW Calculation*

Constellation proposed an alternative methodology for calculating the ambient air offer MW quantity using the resource's Relative MRI multiplied by the difference between its output ratings at 90°F and 100°F. Constellation's amendment sought to preserve the existing flexibility

[11] The IEP was a voluntary program that provided compensation to resources that maintained inventoried energy during extremely cold periods when the system was most stressed. The program ended in 2025.

[12] At NEPOOL members' request, NEPOOL Counsel reviewed the CAR-SA Tariff revisions and found that they reflected the ISO's proposed market design. Memorandum from NEPOOL Counsel to NEPOOL Markets, Reliability, and Transmission Committee Members and Alternates 1 (Oct. 26, 2026), https://www.iso-ne.com/static-assets/documents/100040/a03c_2026_11_4-5_car-sa_nepool_counsel_tariff_review.pdf.

[13] Participants also developed other proposed amendments during the stakeholder process. The ISO incorporated certain stakeholder suggestions into its revised proposal and identified other issues for future assessment. The following presentations describe those proposals: FirstLight (Balancing Ratio proposal within the Markets Committee's purview); FirstLight (seasonal risk allocation proposal within the Reliability Committee's purview); MA AGO (energy storage accreditation); NEPGA (proposals within the Markets Committee and Reliability Committee's purviews); NESCOE (Net CONE assumptions, a transition capacity price cap, and a transition gas demand curve); and Storage Coalition (storage accreditation heuristic and a three-year transition).

for resources with predictable reductions in output at elevated temperatures. The amendment was not supported, receiving a Markets Committee vote of 54.17% in favor.

2. *Vistra – Making the Transition Mechanism's Relaxed Firm-Gas Contracting Requirements Permanent*

Vistra proposed to make permanent the broader firm-gas qualification requirements that the ISO would otherwise apply only during the transition. The amendment would allow qualifying gas contracts meeting North American Energy Standards Board or International Swaps and Derivatives Association firm-service standards to continue satisfying the firm-fuel requirements after the transition. The motion failed on a show of hands vote.

Reliability Committee Consideration and Action

At its November 17 meeting, the Reliability Committee considered the portions of the CAR-SA Proposal under its purview. Those revisions, provided in Attachment B, included changes to Section I.2.2, Section III.1.5, and Section III.12 of the Tariff. The Reliability Committee unanimously recommended Participants Committee support for the CAR-SA Tariff revisions under its purview, with one abstention noted.[14]

Transmission Committee Consideration and Action

At its November 19 meeting, the Transmission Committee considered the Tariff sections of the CAR-SA Proposal under its purview. Those revisions, as provided in Attachment C, included proposed revisions to Tariff Section I.2.2, OATT Sections II.48 and II.52–II.55, and OATT Attachment K, regarding deactivation rules. The Transmission Committee voted unanimously to recommend Participants Committee support for the CAR-SA revisions under its purview, with two abstentions noted.

Budget & Finance Subcommittee Consideration

The Budget & Finance Subcommittee considered the Tariff sections of the CAR-SA Proposal under its purview over the course of various meetings. Those revisions, as provided in Attachment D, include changes to the FAP and Billing Policy. At its November 20 meeting, no member present objected to the CAR-SA-related changes.[15]

Consistent with past practice, Participants are reminded that neither NEPOOL nor the ISO will raise procedural objections at the FERC should any amendments that were considered

[14] Following discussion at the November Reliability Committee meeting, the ISO adopted NEPGA's amendment to allow resources to reconsider their EFORd lookback election every three years, rather than every five years after the 2030 re-election window. The Committee therefore did not vote separately on the amendment.

[15] SYSO and FirstLight provided feedback on the proposed FAP changes. Neither currently intends to advance a related amendment or proposal. Their materials are available here: SYSO and FirstLight.

but not supported by a NEPOOL Technical Committee be presented directly to FERC, notwithstanding that such amendments were not brought to the Participants Committee for a vote. With this understanding, Constellation and Vistra informed us that they do not intend to seek a Participants Committee vote on their amendments that did not receive Markets Committee support.

PLANNED PROCESS FOR PARTICIPANTS COMMITTEE ACTION

The current plan for December 3 Participants Committee consideration is for the Committee to take separate action on each of the following forms of resolution, starting with the Markets Committee-recommended set of Tariff revisions:

> RESOLVED, that in connection with the ISO's CAR-SA Proposal, the Participants Committee supports the changes to Section I.2.2 (Definitions) and Market Rule 1, including Appendices A (Market Monitoring, Reporting and Market Power Mitigation) and F (NCPC Accounting), as recommended by the Markets Committee at its November 2026 meeting and with the non-substantive revisions approved by the Chair and Vice-Chair of the Markets Committee, together with [any changes agreed to by the Participants Committee at this meeting and] such further non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.
>
> RESOLVED, that in connection with the ISO's CAR-SA Proposal, the Participants Committee supports the changes to Section I.2.2 and Market Rule 1 Sections III.1.5 and III.12, as unanimously recommended by the Reliability Committee at its November 17, 2026, meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Reliability Committee.
>
> RESOLVED, that in connection with the ISO's CAR-SA Proposal, the Participants Committee supports the changes to Section I.2.2, Sections II.48 through II.55.3, and OATT Attachment K (Regional System Planning Process), as unanimously recommended by the Transmission Committee at its November 19, 2026, meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.
>
> RESOLVED, that in connection with the ISO's CAR-SA Proposal, the Participants Committee supports the changes to Section I.2.2, the Billing Policy, and the Financial Assurance Policy, as reflected in the materials circulated to this Committee in advance of the meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

I.2 Rules of Construction; Definitions

***

I.2.2. Definitions:

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

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

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

***

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

***

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

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

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

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

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

****

Asset is a Generator Asset, a Demand Response Asset, ~~a component of~~ an On-Peak Demand ~~Capacity Resource~~Asset, ~~or~~ a Seasonal Peak Demand ~~Capacity Resource~~Asset, a Distributed Generation Asset, a Load Management Asset, an Energy Efficiency Asset, ~~a Distributed Energy Resource participating as part of~~ a Demand Response Distributed Energy Resource Aggregation, the **s**ettlement **o**nly **c**omponent of a Demand Response Distributed Energy Resource Aggregation, a Settlement Only Distributed Energy Resource Aggregation, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

****

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

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

****

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

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

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

****

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

***

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

Capacity Commitment Period is the ~~one-year~~ period ~~from June 1 through May 31~~ for which obligations are assumed and payments are made in the ~~Forward~~ Capacity Market ~~and Annual Capacity Market.~~ For the Capacity Commitment Periods occurring prior to June 1, 2028, the Capacity Commitment Period is the one-year period from June 1 through May 31. For all Capacity Commitment Periods beginning on or after June 1, 2028, there shall be two seasonal Capacity Commitment Periods for which Capacity Supply Obligations are assumed and payments are made in the Capacity Market: a Summer Capacity Commitment Period and a Winter Capacity Commitment Period. For the Summer Capacity Commitment Period beginning on June 1, 2028, the Summer Capacity Commitment Period is the five-month period from June 1, 2028 through October 31, 2028. For all Capacity Commitment Periods thereafter, the Summer Capacity Commitment Period is the six-month period from May 1 through October 31 and the Winter Capacity Commitment Period is the six-month period from November 1 through April 30.

***

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

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

Capacity Import Capability is the transfer capability of an external interface determined pursuant to Section III.12.9.2.4.A.

****

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

****

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

****

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

****

Capacity Performance Bilateral is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 ~~or Section III.15.6.3~~ of Market Rule 1.

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

****

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

****

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

Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 or Section III.15.6.1 of Market Rule 1.

***

Capacity Transfer Limit is the level of import capability available for Import Capacity Resources on an external interface after accounting for tie benefits determined pursuant to Section III.15.1.3.

***

Coincident Peak Contribution is a Market Participant's share of the New England Control Area coincident peak demand for the preceding like-season Capacity Commitment Period~~prior calendar year~~ as determined prior to the start of each Capacity Commitment Period, which reflects the sum of the preceding like-season Capacity Commitment Period ~~prior year's annual~~ coincident peak contributions of the customers served by the Market Participant at each Load Asset. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO. For the purposes of determining a Coincident Peak Contribution for the Capacity Commitment Period beginning on June 1, 2028, the preceding like-season period shall be the period between June 1, 2027 and October 31, 2027. For the purposes of determining a Coincident Peak Contribution for the Capacity Commitment Period beginning on November 1, 2028, the preceding like-season shall be the period between November 1, 2027 and April 30, 2028.

***

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

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

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

***

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

***

Daily Capacity Market Settlement are those Forward Capacity Market payments and charges identified in Sections III.13.7.1 (except III.13.7.1.3), III.13.7.5.1 (except III.13.7.5.1.1.10), and III.13.7.5.4 or those Seasonal Capacity Market payments and charges described in Sections III.15.8.1, III.15.8.5.1, III.15.8.5.4, and III.15.8.6.

***

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

***

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

***

Distributed Generation Asset is a type of Asset that is part of a Passive Demand Capacity Resource and that consists of Distributed Generation.

***

Energy Efficiency Asset is a type of Asset that is part of a Passive Demand Capacity Resource and that consists of Energy Efficiency.

***

Energy-Limited Generating Capacity Resource is a type of Generating Capacity Resource described in Section III.15.3.1(a)(ii).

***

Energy Storage Generating Capacity Resource is a type of Generating Capacity Resource described in Section III.15.3.1(a)(iii).

***

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

***

Firm Gas Capacity is the capacity associated with a Capacity Resource that satisfies the election requirements described in Section III.15.2.1.6.

Firm Gas Capacity Offer Portion is a type of offer portion described in Section III.15.4.1(j).

***

Gas Availability Constraint is the constraint described in Section III.12.2.3.

Gas-Constrained Winter Capacity Demand Curve is the demand curve described in Section III.15.1.1.4.

***

Gas Firming Period means the months of December, January, and February of the Winter Capacity Commitment Period.

***

Generating Capacity Resource Without Energy Limitations is a type of Generating Capacity Resource described in Section III.15.3.1(a)(i).

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

Settlement Only Distributed Energy Resource Aggregation and the settlement only component of a Distributed Energy Resource Aggregation are Generator Assets.

***

Global Maximum Capability is the asset-specific capability value calculated by the ISO pursuant to Section III.1.5.4.

***

Historical Forecast Performance Factor is a factor defined in Section III.15.2.1.1.1.2. that is used to determine the Seasonal MRI Capacity of Import Capacity Resources backed by an external Control Area.

***

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

Hybrid Generating Capacity Resource is a type of Generating Capacity Resource described in Section III.15.3.1(a)(iv).

***

Initial Winter Parameters Study is the study that will produce the winter-relevant parameters needed to calculate the Seasonal Demand Anchor Price in accordance with Section III.15.1.1.5(a) for the Capacity Commitment Period beginning on June 1, 2028 (e.g. the system capacity Marginal Reliability Impact value at the system-wide Net Installed Capacity Requirement, Relative MRI, Maximum Capability, and Qualified Capacity values for all resources associated with the CONE technology type). The study shall be conducted, reviewed with stakeholders, and filed with the Commission in accordance with the process set forth in Section III.12.3.

***

Intermittent Power Generating Capacity Resource is a type of Generating Capacity Resource described in Section III.15.3.1(b).

***

Internal Bilateral for Capacity is a type of internal bilateral transaction described in Section III.15.6.3.

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

***

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

***

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

***

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

***

Maximum Capability is the Global Maximum Capability of an Asset or Capacity Resource that is an Intermittent Power Resource, Seasonal Maximum Capability of an Asset or Capacity Resource that is not an Intermittent Power Resource, Seasonal Maximum Capability equivalent of an Import Capacity Resource, and Seasonal Maximum Capability equivalent of a Passive Demand Capacity Resource composed of Energy Efficiency.

***

Measure Life is the estimated time an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction, ~~Annual~~ Seasonal Capacity Auction, or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

***

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1, or submitted by an On-Peak Demand Capacity Resources composed of Energy Efficiency or a Seasonal Peak Demand Capacity Resource composed of Energy Efficiency as part of the qualification process for the ~~Annual~~ Seasonal Capacity Auction pursuant to the requirements of Section III.15.2.1.1.2.1 of Market Rule 1, and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Capacity Resources or Seasonal Peak Demand Capacity Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource project based on measurement and verification studies performed during the Capacity Commitment Period. Measurement and Verification Reference Reports shall no longer be submitted after June 1, 2028.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource with the monthly settlement report for the Forward Capacity Market or ~~Annual~~ Seasonal Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources in operation as of the end of the previous month. Measurement and Verification Summary Reports shall no longer be submitted after June 1, 2028.

***

Monthly MRI Capacity is the amount of a resource's Marginal Reliability Impact Capacity that is eligible to participate in a Monthly Reconfiguration Auction or Capacity Supply Obligation Bilateral during the applicable month and is calculated using the resource's most recent Maximum Capability value at the time of monthly qualification.

Monthly Qualified Capacity is the amount of a resource's Qualified Capacity eligible to participate in a Monthly Reconfiguration Auction or Capacity Supply Obligation Bilateral during the applicable month for those months occurring prior to the Capacity Commitment Period beginning June 1, 2028.

***

MRI Capacity is the amount, determined pursuant to Section III.15.3, that a Capacity Resource may qualify to offer in a Seasonal Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral. MRI Capacity shall be either Seasonal MRI Capacity or Monthly MRI Capacity.

****

Net Installed Capacity Requirement is defined in Section III.12.1,

****

Non-Commercial Capacity is the capacity of a resource that cleared in a Forward Capacity Auction for periods prior to the ~~Annual~~ Seasonal Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, or otherwise acquired a Capacity Supply Obligation and remains on Critical Path Schedule monitoring as of June 1, 2028, for some or all of its capacity that acquired a Capacity Supply Obligation.

****

Non-Firm Gas Capacity Offer Portion is a type of offer portion described in Section III.15.4.1(j).

****

Passive Demand Capacity Resource is a type of Demand Capacity Resource composed of either a Seasonal Peak Demand Capacity Resource, an On-Peak Demand Capacity Resource, Energy Efficiency Asset, Distributed Generation Asset, or Load Management Asset.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4 ~~or Section III.15.7.1.5.4~~.

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

****

Pivotal Supplier Test Identified Capacity is, as described in Section III.A.23.1, the Seasonal MRI Capacity from: (i) Generating Capacity Resources, excluding Pivotal Supplier Test Non-Firm Gas Capacity Non-Firm Gas Capacity, and (ii) Demand Capacity Resources.

Pivotal Supplier Test Non-Firm Gas Capacity is, as described in Section III.A.23.1, the Seasonal MRI Capacity from Generating Capacity Resources subject to the Gas Availability Constraint.

***

Proxy Capacity Offer is a type of offer used in the ~~Annual~~ Capacity Market.

***

Qualification Data Submission Deadline is a date specified in the Capacity Auction Calendar by which a Lead Market Participant seeking to have a resource participate in ~~the Annual~~ the Seasonal Capacity Auction must submit qualification materials pursuant to Section III.15.2.1.1.

Qualification Data Submission Package is the package submitted to the ISO by a Lead Market Participant seeking to qualify a resource for ~~the Annual~~ the Seasonal Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral pursuant to Section III.15.2.1.1.

***

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined prior to the 2028-2029 Capacity Commitment Period in the Forward Capacity Market qualification processes~~, or, for the 2028-2029 Capacity Commitment Period and all Capacity Commitment Periods thereafter, through the Annual Capacity Market qualification and demonstration processes~~.

~~**Qualified Capacity Challenge and Restoration Plan Submission Window** is the period set forth in the Capacity Auction Calendar during which a Lead Market Participant may challenge the ISO-calculated summer and winter Qualified Capacity values of a Capacity Resource or submit a restoration plan to remedy a significant decrease in a Seasonal Qualified Capacity value of a Capacity Resource.~~

~~**Qualified Capacity Challenge and Restoration Plan Submission Deadline** is a date set forth in the Capacity Auction Calendar by which a Lead Market Participant may challenge the ISO-calculated summer and winter Qualified Capacity values of a Capacity Resource or submit a restoration plan to remedy a significant decrease in Qualified Capacity of a Capacity Resource..~~

***

Rationing Minimum Limit is the MW quantity below which a Capacity Offer may not be rationed in the ~~Annual~~ Seasonal Capacity Auction.

***

Relative Marginal Reliability Impact (Relative MRI) is a value determined pursuant to Section III.12.1.2 comparing a resource-specific Marginal Reliability Impact value to the Marginal Reliability Impact value of a perfect Capacity Resource.

***

Resource Adequacy Assessment Consultation Deadline is the deadline described in Section III.12.7.3.5 for consultation regarding resource-specific Resource Adequacy Assessment inputs.

***

Seasonal Capacity Auction is the Summer Capacity Auction or Winter Capacity Auction processes carried out pursuant to Section III.15.4 of Market Rule 1.

Seasonal Capacity Market is the seasonal market for procuring capacity in the New England Control Area, as described in Section III.15 of Market Rule 1.

***

Seasonal Demand Anchor Price is the seasonally-specific price, expressed in $/kW-month of Marginal Reliability Impact Capacity, determined pursuant to Section III.15.1.1.5.

Seasonal Dependable Capability is the asset-specific capability value calculated by the ISO pursuant to Section III.1.5.6.

***

Seasonal Loss of Load Expectation (LOLE) Target is the resource adequacy planning criteria described in Section III.12.1(a).

Seasonal Maximum Capability is the asset-specific capability value calculated by the ISO pursuant to Section III.1.5.5.

Seasonal MRI Capacity Notification Date is a date described in the Capacity Auction Calendar by which the ISO shall notify Market Participants of their Seasonal MRI Capacity Value for the upcoming Capacity Commitment Period.

Seasonal MRI Capacity may refer to the Seasonal MRI Capacity of a Capacity Resource or the Seasonal MRI Capacity of a Capacity Market parameter. The Seasonal MRI Capacity values of a Capacity Resource shall be the summer and winter Marginal Reliability Impact Capacity values determined pursuant to Section III.15.3. The Seasonal MRI Capacity of a Capacity Market parameter other than that which is assigned to a Capacity Resource pursuant to Section III.15.3 shall be the MRI equivalent of the value developed pursuant to Section III.12 or Section III.15.

***

Seasonal Qualified Inventory is defined in Section III.12.7.3.4(a).

***

Summer Capacity Auction is the Seasonal Capacity Auction through which Capacity Supply Obligations are assumed for the Summer Capacity Commitment Period.

Summer Capacity Commitment Period is one of two annually occurring Capacity Commitment Periods for which Capacity Supply Obligations are assumed and payments are made in the Seasonal Capacity Auction. The Summer Capacity Commitment Period is the six-month period from May 1 through October 31. Notwithstanding the foregoing, the first Summer Capacity Commitment Period for which Capacity Supply Obligations are assumed and payments are made in the Seasonal Capacity Auction shall be the five-month period from June 1, 2028 through October 31, 2028.

***

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) ~~or Section III.15.3.2.1(b)~~ of Market Rule 1.

Summer QC-to-MCap Ratio is a value used in the calculation of a resource's Transition Seasonal MRI Capacity pursuant to Section III.15.B.1.2 or Transition Monthly MRI Capacity pursuant to Section III.15.B.1.3, as calculated pursuant to Section III.15.1.1.

***

Transition Monthly MRI Capacity is a value calculated pursuant to Section III.15.B.1 to be used in place of a Capacity Resource's Monthly MRI Capacity for purposes of the Monthly Reconfiguration Auctions and the monthly trading activities associated with Capacity Commitment Periods occurring between June 1, 2028 and April 30, 2031.

***

Transition Seasonal MRI Capacity may refer to the Transition Seasonal MRI Capacity of a Capacity Resource or the Transition Seasonal MRI Capacity of a Capacity Market parameter. The Transition Seasonal MRI Capacity value of a Capacity Resource is a value calculated pursuant to Section III.15.B.1 to be used in place of a Capacity Resource's Seasonal MRI Capacity for purposes of the Seasonal Capacity Auctions associated with Capacity Commitment Periods occurring between June 1, 2028 and April 30, 2031. The Transition Seasonal MRI Capacity of a Capacity Market parameter other than that which is assigned to a Capacity Resource pursuant to Section III.15.3 is described in Section III.15.B.2.

***

Unexpected Full Forced Outage is a type of outage described in Section III.15.2.8.

***

Winter Capacity Auction is the Seasonal Capacity Auction through which Capacity Supply Obligations are assumed for the Winter Capacity Commitment Period.

Winter Capacity Commitment Period is one of two annually occurring Capacity Commitment Periods for which Capacity Supply Obligations are assumed and payments are made in the Seasonal Capacity Auction. The Winter Capacity Commitment Period is the six-month period from November 1 through April 30.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) ~~or Section III.15.3.2.2(b)~~ of Market Rule 1.

Winter QC-to-MCap Ratio is a value used in the calculation of a resource's Transition Seasonal MRI Capacity pursuant to Section III.15.B.1.2 or Transition Monthly MRI Capacity pursuant to Section III.15.B.1.3, as calculated pursuant to Section III.15.1.1.

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STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals ~~for Market~~ for Energy, Internal Bilaterals for Capacity, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, ~~Capacity Performance Bilaterals,~~ and the transactions described in ~~Sections III.9.4.1 and transactions described in Sections (internal bilateral transactions that transfer Forward Reserve Obligations), and~~ Sections III.13.1.6 (Self-Supplied ~~Supplied~~ FCA Resources) and III.15.2.7(Self-Supplied Capacity 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, Internal Bilaterals for Capacity, 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~~ and the transactions described in Sections III.13.1.6 (Self-Supplied FCA Resources) and III.15.2.7 (Self-Supplied Capacity 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:

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. Seasonal Claimed Capability values of a Generating Capacity Resource shall no longer be established or maintained after August 31, 2027.

(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. Seasonal DR Audit values of an Active Demand Capacity Resource shall no longer be established or maintained after August 31, 2027.

(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 Seasonal DECR Audit Value.

(a) A Seasonal DECR Audit Value must be established and maintained for all Distributed Energy Capacity Resources. A summer Seasonal DECR Audit Value is established for use from June 1 through September 30 and a winter Seasonal DECR Audit Value is established for use from October 1 through May 31.

(b) The Seasonal DECR Audit Value of Distributed Energy Capacity Resources is the sum of: the Seasonal Claimed Capabilities of Distributed Energy Resource Aggregations participating as a Generator Asset or a Settlement Only Distributed Energy Resource Aggregation; the Seasonal DR Audit value of a Distributed Energy Resource Aggregation participating as a Demand Response Resource; and the Seasonal DRDERA Audit values of the Demand Response

Distributed Energy Resource Aggregations comprising the Distributed Energy Capacity Resource.

(c) The Seasonal Claimed Capability of a Settlement Only Distributed Energy Resource is:

a. Based upon review of historical data for non-intermittent daily cycle hydro.

b. 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 as reflected in hourly revenue metering data.

c. For all other Settlement Only Distributed Energy Resources, the minimum of: (1) the Settlement Only Distributed Energy Resource's current Establish Claimed Capability Audit value and (2) the Settlement Only Distributed Energy Resource's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

The Seasonal DRDERA Audit value for Distributed Energy Resource Aggregations participating as Demand Response Distributed Energy Resource Aggregations is the value of the audit for the aggregation performed pursuant to Section III.1.5.1.3.2**.**

III.1.7.14 ~~[Reserved.]~~ Capability Values of Capacity Resources

For the Capacity Commitment Period beginning on June 1, 2028, and all Capacity Commitment Periods thereafter, the ISO shall determine the Global Maximum Capability value, Seasonal Maximum Capability values, and Seasonal Dependable Capability values of Generating Capacity Resources, Active Demand Capacity Resources, Passive Demand Capacity Resources, and Distributed Energy Capacity Resources as set forth in this Section III.1.7.14.

(a) **Global Maximum Capability**. A Global Maximum Capability value must be established and maintained for all Generating Capacity Resources, Active Demand Capacity Resources, Passive Demand Capacity Resources, and Distributed Energy Capacity Resources. The Global Maximum Capability of a Capacity Resource shall be the sum of the Global Maximum Capabilities of the Assets that are mapped to the Capacity Resource pursuant to the qualification process described in Section III.15.2.

(b) **Seasonal Maximum Capability**. A Seasonal Maximum Capability value must be established and maintained for all Generating Capacity Resources, Active Demand Capacity Resources, Distributed Energy Capacity Resources, non-energy efficiency On-Peak Demand Capacity Resources, and non-energy efficiency Seasonal Peak Demand Capacity Resources. A summer Seasonal Maximum Capability shall be established for use from May 1 through October 31 and a winter Seasonal Maximum Capability shall be established for use from November 1 through April 30. The Seasonal Maximum Capability of a Capacity Resource shall be the sum of the

Seasonal Maximum Capabilities of the Assets that are mapped to the Capacity Resource pursuant to the qualification process described in Section III.15.2.

~~(a)~~ **Seasonal Dependable Capability.** A Seasonal Dependable Capability value must be established and maintained for all Generating Capacity Resources, Active Demand Capacity Resources, Passive Demand Capacity Resources, and Distributed Energy Capacity Resources. A summer Seasonal Dependable Capability shall be established for use from May 1 through October 31 and a winter Seasonal Dependable Capability shall be established for use from November 1 through April 30. The Seasonal Dependable Capability of a Capacity Resource shall be the sum of the Seasonal Dependable Capabilities of the Assets that are mapped to the Capacity Resource pursuant to the qualification process described in Section III.15.2.

(c)

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, Demand Response Distributed Energy Resource Aggregation, 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.

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 (ii) 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 (ii) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) [Reserved.]~~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 through an import-constrained Reserve Zone that are not associated with a Capacity Supply Obligation:

(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~~ Capacity ~~Offer~~ Resource, or portion thereof,~~Segment~~ that did not receive a Capacity Supply Obligation in the ~~Annual~~ Seasonal Capacity Auction during the relevant period, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the unobligated ~~Export~~ Capacity Resource, or portion thereof~~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 through an import-constrained Reserve Zone that are not associated with a Capacity Supply Obligation: 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 through an import-constrained Reserve Zone that are not associated with a Capacity Supply Obligation: Market Participants with ~~Capacity Export Through Import Constrained Zone Transactions and Annual Capacity Auction Cleared~~ Export Transactions through an import-constrained Reserve Zone that are not associated with a Capacity Supply Obligation 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

III.3 Accounting And Billing

III.3.1 Introduction.

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

If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.3.2 Market Participants.

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

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

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

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

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

the sum of all Market Participants' Real-Time Load Obligations, Real-Time Generation Obligations, and Real-Time Demand Reduction Obligations over all Locations, measured as absolute values, excluding contributions to Real-Time Load Obligations and Real-Time Generation Obligations from Coordinated External Transactions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(r) **Real-Time Energy Market Charge/Credit For Demand Response Distributed Energy Resource Aggregations –** For each Market Participant for each settlement interval, the ISO shall calculate a charge or credit to the Market Participant for its net purchases from, or sales to the Real-Time

III.10 Settlement for Real-Time Reserves

For purposes of this Section III.10, unless otherwise expressly stated, the settlement interval is five minutes. If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.10.1 Reserve Quantity For Settlement

Each Resource receiving a Real-Time Reserve Designation pursuant to Section III.1.7.19 shall receive, for each settlement interval, a Reserve Quantity For Settlement. The Reserve Quantity For Settlement shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve. The Reserve Quantity For Settlement values will equal the corresponding Real-Time Reserve Designation values, adjusted downward after the fact to account for actual reserve capability based on Metered Quantity For Settlement.

III.10.2 Real-Time Reserve Credits

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

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

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

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

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

III.10.3 Real-Time Reserve Charges.

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

$$\text{Real-Time Reserve Charge}_{k,i} = [\text{Reserve Charge Allocation MW}_{k,i}] \times [\text{RT_CHRG_RT}_i]$$

Where:

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

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

$RT_CHRG_RT_i$ = [IRT_SUP_PMNT]/RT_P_WTD_LD_OB] x [RT_P_RATIO] for TMSR, TMNSR, or TMOR, as applicable.

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

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

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

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

The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), an ~~Capacity Export Through Import Constrained Zone Transaction or an~~ Export Transactions through an import-constrained Reserve Zone that is not associated with a Capacity Supply Obligation ~~FCA Cleared Export Transaction~~ shall be considered to be within the Load Zone from which the External Transaction is exporting for the purpose of calculating Real-Time Reserve Charges. ~~The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.~~

III.10.4 Forward Reserve Obligation Charges.

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

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

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

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

III.10.4.2 Forward Reserve Obligation Charge Megawatts.

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

III.10.4.3 Forward Reserve Obligation Charge.

The Forward Reserve Obligation Charge will be calculated as follows:

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

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

III.15. ~~Annual~~ Seasonal Capacity Market.

(a) ~~Annual~~ Capacity Market Overview.

The ISO shall administer a~~n annual~~ seasonal market for capacity (~~Annual~~ "Seasonal Capacity Market") in accordance with the provisions of this Section III.15. For all Capacity Commitment Periods beginning on or after June 1, 2028, there shall be two Capacity Commitment Periods each year for which Capacity Supply Obligations are assumed and payments are made in the Capacity Market: a Summer Capacity Commitment Period and a Winter Capacity Commitment Period. ~~For each one-year period from June 1 through May 31, starting with the period June 1, 2028 to May 31, 2029, for which Capacity Supply Obligations are assumed and payments are made in the Annual Capacity Market ("Capacity Commitment Period"),~~ For each Capacity Commitment Period, the ISO shall conduct a~~n~~ ~~Annual~~ Seasonal Capacity Auction in accordance with the provisions of Section III.15.4 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the ~~Annual~~ Seasonal Capacity Auction, a resource must have ~~Qualified~~ Seasonal MRI Capacity resulting from the ~~Annual~~ Seasonal Capacity Auction qualification process in accordance with the provisions of Sections III.15.2 and III.15.3. Obligations as~~c~~sociated with the ~~Annual~~ Seasonal Capacity ~~Market~~ Auction may be traded during ISO-administered Monthly Reconfiguration Auctions and monthly bilateral transactions, in accordance with Section III.15.5 and Section III.15.6, respectively. The obligations of resources with Capacity Supply Obligations resulting from ~~the~~a ~~Annual~~ Seasonal Capacity Auction, Monthly Reconfiguration Auction~~s~~, ~~and~~ or monthly bilateral transaction~~s~~, as well as Capacity Performance Payments, are set forth in Section III.15.7. Payments and charges resulting from participation in the ~~Annual~~ Seasonal Capacity ~~Market~~Auction, Monthly Reconfiguration Auction~~s~~, and bilateral transactions are set forth in Section III.15.8. The publication of auction-related information is set forth in Section III.15.9.

(b) Capacity Auction Calendar.

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2028, and for each Capacity Commitment Period thereafter, the ISO shall publish a calendar of dates and deadlines for the administration of the Capacity Market, with the dates and deadlines being generally consistent for each year of the Seasonal~~Annual~~ Capacity Auction cycle. The Capacity Auction Calendar shall include specific dates and deadlines for all such Capacity Market dates and deadlines defined in this Section III.15 and related Tariff provisions. The following defines several milestone dates and deadlines~~.~~:

(1) the Qualification Data Submission Deadline for the ~~Annual~~ Summer Capacity Auction shall occur during the month of December~~February~~;

(2) the Capacity Demonstration Deadline for the ~~Annual~~ Summer Capacity Auction shall occur during the month of ~~April~~March;

(3) the ~~Annual~~ Summer Capacity Auction shall occur during the month of ~~May~~April;

(4) the Qualification Data Submission Deadline for the Winter Capacity Auction shall occur during the month of June;

(5) the Capacity Demonstration Deadline for the Winter Capacity Auction shall occur during the month of September; and

(6) the Winter Capacity Auction shall occur during the month of October.

Notwithstanding the foregoing, for the Summer Capacity Commitment Period beginning on June 1, 2028, the Qualification Data Submission Deadline shall occur during the month of January, the Capacity Demonstration Deadline shall occur during the month of March, and Seasonal Capacity Auction shall occur during the month of May.

(c) Modification of Capacity Auction Calendar.

The ISO may, on a prospective basis, reasonably revise any date or deadline in the Capacity Auction Calendar with written notice of such revision to each Governance Participant in the manner specified in Section 17.11(b) of the Participants Agreement prior to the occurrence of the date or deadline being revised. In the event a Market Participant fails to meet a deadline in the Capacity Auction Calendar for submission of information or data, the ISO shall extend such deadline for that Market Participant upon receipt of an order from the Commission granting the Market Participant's request for a waiver of such deadline for good cause shown. In no event shall a date or deadline be extended, prospectively by the ISO or retroactively by filing of a Market Participant, should doing so interfere with the ISO's effective administration of the Capacity Market.

(d) Effectiveness for the Summer 2028~~-2029~~ Capacity Commitment Period and Thereafter.

The provisions of this Section III.15 are effective for the Capacity Commitment Period that begins~~runs from~~ on June 1, 2028 ~~through May 31, 2029~~ and all Capacity Commitment Periods thereafter. Unless otherwise expressly stated, the provisions of this Section III.15 are not applicable to the Forward Capacity Market. Section III.13, addressing the administration of the Forward Capacity Market shall continue to be effective for Capacity Commitment Periods through May 31, 2028. Unless otherwise expressly stated,

the provisions of Section III.13 are not applicable to the ~~Annual~~ Seasonal Capacity ~~Market~~Auction, Monthly Reconfiguration Auctions and monthly bilateral transactions addressed in this Section III.15 of Market Rule 1.

III.15.A. Non-Commercial Capacity Transition Rules.

All Capacity Resources that are on critical path schedule monitoring pursuant to Section III.13.3 as of June 1, 2028 are subject to the provisions of this Section III.15.A.

The ISO shall monitor the Non-Commercial Capacity resource's compliance with its critical path schedule ~~from the time the ISO approves the request~~ until the resource achieves FCM Commercial Operation, is terminated pursuant to Section III.15.A.2.1, or withdraws from critical path schedule monitoring pursuant to Section III.15.A.2.3.

III.15.A.1. Non-Commercial Capacity Resource Critical Path Schedule Reports.

For each resource that is being monitored for compliance with its critical path schedule, the Lead Market Participant for that resource must provide a written critical path schedule report to the ISO no later than five Business Days after the end of each calendar quarter. If the Lead Market Participant does not provide a written critical path schedule report to the ISO by the fifth Business Day after the end of the calendar quarter, then the ISO shall issue a notice thereof to the Lead Market Participant. If the Lead Market Participant fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.15.A.2.1. Each critical path schedule report shall include a complete updated version of the critical path schedule as described in Section III.15.A.1.1 through Section III.15.A.1.3.

III.15.A.1.1. Updated Critical Path Schedule.

The critical path schedule report must include a complete updated version of the critical path schedule as described in Section III.15.A.1, dated contemporaneously with the submission of the critical path schedule report. The updated critical path schedule must clearly indicate if the Lead Market Participant is proposing to change any of the milestones or dates from the previously submitted version of the critical path schedule, and must include an explanation of any such proposed changes. In the critical path schedule report, the Lead Market Participant must also explain in detail any proposed changes to the project design and the potential impact of such changes on the amount of capacity the resource will be able to provide.

III.15.A.1.2. Documentation of Milestones Achieved.

(a) For all new resources (except for Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW,

which are discussed in Section III.15.A.1.2(b)), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Lead Market Participant must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Major Permits**. For each major permit described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the permit was applied for and obtained as described in the critical path schedule. For permit applications, this documentation could include a dated copy of the permit application or cover letter requesting the permit. For approved permits, this documentation could include a dated copy of the approved permit or letter granting the permit from the permitting authority.

(ii) **Project Financing Closing**. The Lead Market Participant shall provide documentation showing that the sources of financing identified in the critical path schedule have committed to provide the amount of financing described in the critical path schedule. This documentation could include copies of commitment letters from the sources of financing.

(iii) **Major Equipment Orders**. For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the equipment was ordered as described in the critical path schedule. This documentation should include a copy of a dated confirmation of the order from the manufacturer or supplier. This documentation should confirm scheduled delivery dates consistent with milestone Section III.15.A.1.2(a)(v).

(iv) **Substantial Site Construction.** The Lead Market Participant shall provide documentation showing that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs.

(v) **Major Equipment Delivery**. For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the equipment was delivered to the project site and received as preliminarily acceptable as described in the critical path schedule. This documentation should include a copy of a dated confirmation of delivery to the project site.

(vi) **Major Equipment Testing.** For each major component described in the critical path schedule, the Lead Market Participant shall provide documentation showing that the component was tested, including major systems testing as appropriate for the specific technology as described in the critical path schedule, and that the test results demonstrate the equipment's suitability to allow, in conjunction with other major components, subsequent operation of the project in accordance with the amount of capacity subject to critical path schedule monitoring in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning**. The Lead Market Participant shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity subject to critical path schedule monitoring. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Lead Market Participant is not required to provide documentation of Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) to the ISO as part of the ISO's critical path schedule monitoring. The ISO shall confirm that the resource has achieved Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) as described in the critical path schedule through the resource's compliance with the other relevant requirements of the Transmission, Markets and Services Tariff and the ISO New England System Rules.

(ix) **Transmission Upgrades**. The Lead Market Participant shall provide documentation showing that all interconnection facilities and upgrades identified for the project associated with the resource in a Transitional Cluster Study, Cluster Study, or Cluster Restudy (conducted pursuant to Section 7.5 of Schedule 22, Section 7.5 of Schedule 23, or Section 7.5 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff), or interconnection request or agreement under applicable state tariff, rules or procedures, have been completed.

(b) For Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Lead Market

Participant must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Substantial Project Completion**. The Lead Market Participant shall provide documentation showing the resource will be capable of providing its total offered demand reduction value as described in the New Demand Capacity Resource Qualification Package by the proposed Commercial Operation Date reported in the critical path schedule report.

(ii) **Additional Requirements**. For each customer and each prospective customer the Lead Market Participant shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's Asset has been registered with the ISO, then the Lead Market Participant shall also provide the Asset identification number.

III.15.A.1.3. Additional Relevant Information.

The Lead Market Participant must include in the critical path schedule report any other information regarding the status or progress of the project or any of the project milestones that might be relevant to the ISO's evaluation of the feasibility of the project being built in accordance with the critical path schedule.

III.15.A.2. Failure to Meet Critical Path Schedule.

If the ISO determines that any critical path schedule milestone date has been missed, or if the Lead Market Participant proposes a change to any milestone date in a quarterly critical path schedule report (as described in Section III.15.A.1), then the ISO shall consult with the Lead Market Participant to determine the impact of the missed milestone or proposed revision, and shall determine a revised date for the milestone and for any other milestones affected by the change. If a milestone date is revised for any reason, the ISO may require the Lead Market Participant to submit a written report to the ISO on the fifth Business Day of each month until the revised milestone is achieved detailing the progress toward meeting the revised milestone. If the Lead Market Participant does not provide a written critical path schedule report to the ISO on the fifth Business Day of a month, then the ISO shall issue a notice thereof to the Lead Market Participant. If the Lead Market Participant fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.15.A.2.1. Such a monthly reporting requirement, if imposed, shall be in addition to the quarterly critical path schedule reports described in Section III.15.A.1.

III.15.A.2.1. Termination of Critical Path Schedule Monitoring.

If a Lead Market Participant fails to comply with the requirements of Sections III.15.A.1 or III.15.A.2, or if, as a result of milestone date revisions, the date by which a resource will have achieved all its critical path schedule milestones is more than two years after the beginning of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation, then the ISO, after consultation with the Lead Market Participant, shall have the right, through a filing with the Commission, to terminate the resource's status on critical path schedule monitoring, provided that, where a Lead Market Participant voluntarily withdraws its resource from critical path schedule monitoring in accordance with Section III.15.A.2.3 no filing with the Commission shall be necessary. Upon Commission ruling, the Lead Market Participant shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation. If in these circumstances, however, the ISO does not take steps to terminate the resource and instead permits the Lead Market Participant to continue on critical path schedule monitoring, such continuation shall be subject to the ISO's right to revoke that permission and to file with the Commission to terminate the resource, and subject to continued reporting by the Lead Market Participant in accordance with Section III.15.A.1.

III.15.A.2.2. Termination of Interconnection Agreement.

If the ISO terminates, or files with the Commission to terminate, a resource's ability to remain on critical path schedule monitoring, the ISO shall have the right to terminate the Interconnection Agreement with that resource through a filing with the Commission and upon Commission ruling. The ISO shall also reduce the resource's assigned capacity interconnection service (or equivalent for resources not subject to the ISO Interconnection Procedures).

III.15.A.2.3. Withdrawal from Critical Path Schedule Monitoring.

A Lead Market Participant may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO.

III.15.A.3. Financial Assurance.

The financial assurance requirements for Designated FCM Participants offering Non-Commercial Capacity into the Forward Capacity Auction, as described in Section VII.B.2.b the ISO New England Financial Assurance Policy, shall continue to apply to all Capacity Resources that are subject to the provisions of this Section III.15.A.

Once a resource with Non-Commercial Capacity achieves commercial operation, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as a resource that has achieved Capacity Market Commercial Operation, as governed by the ISO New England Financial Assurance Policy.

If a Capacity Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited. Any financial assurance that is forfeited pursuant to Section III.15.A shall be used to reduce charges incurred by load in the relevant Capacity Zone.

III.15.A.4. Demonstrating FCM Commercial Operation

All Capacity Resources subject to the provisions of this Section III.15.A shall achieve commercial operation, for purposes of ending critical path schedule monitoring, in accordance with the FCM Commercial Operation requirements specified in Section III.13.3.8 or the demonstration requirement described in Section III.15.2.6.

III.15.A.5. Settlement of Qualification Process Cost Reimbursement Deposit.

Upon the date on which the entire resource is no longer on critical path schedule monitoring, the ISO shall provide the Lead Market Participant with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff. All Capacity Resources that are subject to the provisions of this Section III.15.A shall be subject to the Forward Capacity Market payment and refund requirements as set forth in Section III.13.1.9.3.2 of the Tariff.

III.15.B. Accreditation, Demand Curves, and Gas Firming Requirements Transition Rules.

III.15.B.1. Qualified Capacity to Seasonal MRI Capacity Accreditation Transition Rules.

Notwithstanding anything to the contrary in the remainder of Section III.15 and except as provided in Section III.15.B.1.5, for purposes of the Seasonal Capacity Auctions, the Monthly Reconfiguration Auctions, and the monthly trading activities associated with Capacity Commitment Periods occurring between June 1, 2028 and April 30, 2031, a Capacity Resource's Transition Seasonal MRI Capacity and Transition Monthly MRI Capacity calculated pursuant to this Section III.15.B.1 shall be used in place of the Capacity Resource's Seasonal MRI Capacity and Monthly MRI Capacity calculated pursuant to Section III.15.3.

III.15.B.1.1. QC-to-MCap Ratio.

During the qualification process of the Seasonal Capacity Auction for the Capacity Commitment Period beginning June 1, 2028, the ISO shall calculate a Summer QC-to-MCap Ratio and a Winter QC-to-MCap Ratio for each Capacity Resource in accordance with this Section III.15.B.1.1. A resource's Summer QC-to-MCap Ratio shall be used in the calculation of a resource's Transition Seasonal MRI Capacity pursuant to Section III.15.B.1.2 for any Seasonal Capacity Auction for a Summer Capacity Commitment Period or in the calculation of a resource's Transition Monthly MRI Capacity pursuant to Section III.15.B.1.3 for any Monthly Reconfiguration Auction or monthly trading activity associated with a Summer Capacity Commitment Period. A resource's Winter QC-to-MCap Ratio shall be used in the calculation of a resource's Transition Seasonal MRI Capacity pursuant to Section III.15.B.1.2 for any Seasonal Capacity Auction for any Winter Capacity Commitment Period or in the calculation of a resource's Transition Monthly MRI Capacity pursuant to Section III.15.B.1.3 for any Monthly Reconfiguration Auction or monthly trading activity associated with a Winter Capacity Commitment Period. A resource's Summer QC-to-MCap Ratio and Winter QC-to-MCap Ratio shall be capped at 1.

(a) *Resources With Qualified Capacity Values.* For a Capacity Resource that participated in the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2027, the resource's Summer QC-to-MCap Ratio shall equal the resource's summer Qualified Capacity (as calculated for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2027) divided by the resource's summer Maximum Capability (as calculated for the Seasonal Capacity Auction for the Summer Capacity Commitment Period beginning June 1, 2028). The resource's Winter QC-to-MCap Ratio shall equal the resource's winter Qualified Capacity (as

calculated for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2027) divided by the resource's winter Maximum Capability (as calculated for the Seasonal Capacity Auction for the Winter Capacity Commitment Period beginning November 1, 2028).

(b) *Resources Without Qualified Capacity Values.* Capacity Resources that did not participate in the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2027 or did not qualify to participate in the Seasonal Capacity Auction for the Capacity Commitment Period beginning June 1, 2028 will receive a class-based Summer QC-to-MCap Ratio and Winter QC-to-MCap Ratio for purposes of Section III.15.B.1.2 and Section III.15.B.1.3. The class-based Summer QC-to-MCap Ratio shall be calculated as the sum of the summer Qualified Capacity values (as calculated for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2027) for all resources in a class divided by the sum of the summer Maximum Capability (as calculated for the Seasonal Capacity Auction for the Summer Capacity Commitment Period beginning June 1, 2028) for all resources in a class. The class-based Winter QC-to-MCap Ratio shall be calculated as the sum of the winter Qualified Capacity values (as calculated for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2027) for all resources in a class divided by the sum of the winter Maximum Capability (as calculated for the Seasonal Capacity Auction for the Winter Capacity Commitment Period beginning November 1, 2028) for all resources in a class. The classes to be used for calculating the class-based Summer QC-to-MCap Ratio and class-based Winter QC-to-MCap Ratio pursuant to this Section III.15.B.1.1(b) are those defined in Section III.15.3.1.

III.15.B.1.2. Transition Seasonal MRI Capacity Values.

A resource's Transition Seasonal MRI Capacity shall be calculated for use in the Seasonal Capacity Auctions for the Capacity Commitment Periods occurring between June 1, 2028 and April 30, 2031 in accordance with the following formulas:

(a) For each Seasonal Capacity Auction for a Capacity Commitment Period occurring between June 1, 2028 and April 30, 2029, a resource's Transition Seasonal MRI Capacity shall equal the sum of one-fourth of the resource's Seasonal MRI Capacity and three-fourths of the resource's Seasonal Estimated QC.

(b) For each Seasonal Capacity Auction for a Capacity Commitment Period occurring between May 1, 2029 and April 30, 2030, a resource's Transition Seasonal MRI Capacity shall equal the sum of half of the resource's Seasonal MRI Capacity and half of the resource's Seasonal Estimated QC.

(c) For each Seasonal Capacity Auction for a Capacity Commitment Period occurring between May 1, 2030 and April 30, 2031, a resource's Transition Seasonal MRI Capacity shall equal the sum of three-fourths of the resource's Seasonal MRI Capacity and one-fourth of the resource's Seasonal Estimated QC.

Where:

Seasonal MRI Capacity	=	the resource's Seasonal MRI Capacity value calculated pursuant to Section III.15.3.2 for the relevant Seasonal Capacity Auction. However, for the Seasonal Capacity Auctions for the Winter Capacity Commitment Periods beginning November 1, 2028, November 1, 2029, and November 1, 2030, in the calculation of the Seasonal MRI Capacity value of each Energy Storage Generating Capacity Resource, each resource's Relative MRI shall be calculated in accordance with Section III.15.B.1.4.
Seasonal Estimated QC	=	the product of the resource's Maximum Capability value calculated for the relevant Seasonal Capacity Auction and the resource's Summer QC-to-MCap Ratio or Winter QC-to-MCap Ratio, as applicable.

III.15.B.1.3. Transition Monthly MRI Capacity Values.

A resource's Transition Monthly MRI Capacity for any Monthly Reconfiguration Auction or monthly trading activity occurring between June 1, 2028 and April 30, 2031 shall be calculated in accordance with the following formulas:

(a) For the Capacity Commitment Periods occurring between June 1, 2028 and April 30, 2029, a resource's Transition Monthly MRI Capacity shall equal the sum of one-fourth of the resource's Monthly MRI Capacity and three-fourths of the resource's Monthly Estimated QC.

(b) For the Capacity Commitment Periods occurring between May 1, 2029 and April 30, 2030, a resource's Transition Monthly MRI Capacity shall equal the sum of half of the resource's Monthly MRI Capacity and half of the resource's Monthly Estimated QC.

(c) For the Capacity Commitment Periods occurring between May 1, 2030 and April 30, 2031, a resource's Transition Monthly MRI Capacity shall equal the sum of three-fourths of the resource's Monthly MRI Capacity and one-fourth of the resource's Monthly Estimated QC.

Where:

Monthly MRI Capacity	=	the resource's Monthly MRI Capacity value calculated pursuant to Section III.15.3.2 for the relevant Monthly Reconfiguration Auction or Capacity Supply Obligation Bilateral. However, for the Winter Capacity Commitment Periods beginning November 1, 2028, November 1, 2029, and November 1, 2030, in the calculation of the Monthly MRI Capacity value of each Energy Storage Generating Capacity Resource, each resource's Relative MRI shall be calculated in accordance with Section III.15.B.1.4.
Monthly Estimated QC	=	the product of the resource's Maximum Capability value calculated for the relevant Monthly Reconfiguration Auction or Capacity Supply Obligation Bilateral and the resource's Summer QC-to-MCap Ratio or Winter QC-to-MCap Ratio, as applicable.

III.15.B.1.4. Energy Storage Generating Capacity Resources Transition Relative MRI Winter Adjustment.

For the Seasonal Capacity Auctions for the Winter Capacity Commitment Periods beginning November 1, 2028, November 1, 2029, and November 1, 2030, for purposes of calculating an Energy Storage Generating Capacity Resource's Transition Seasonal MRI Capacity or Transition Monthly MRI Capacity pursuant to this Section III.15.B.1, each resource's Relative MRI shall be calculated in accordance with the below formula:

$$ES\ Transition\ rMRI = \min\left(1,\ \frac{rMRI_{winter}}{rMRI_{winter,16}}\right)$$

Where:

$rMRI_{winter}$ = the Energy Storage Generating Capacity Resource's Relative MRI calculated in accordance with Sections III.12.1.2 and III.15.3 (including the adjustment specified in Section III.15.3.3).

$rMRI_{winter,16}$ = the Relative MRI of a hypothetical Energy Storage Generating Capacity Resource with 16-hour duration and an EFORd of 0%, as adjusted pursuant to Section III.15.3.3.

III.15.B.1.5. Exceptions to Qualified Capacity to Seasonal MRI Capacity Accreditation Transition Rules.

Notwithstanding anything to the contrary in this Section III.15.B.1, for (i) any Distributed Energy Capacity Resource or (ii) any Capacity Resource that is part of a resource technology type used for accreditation that did not (for Capacity Market accreditation purposes) exist at the time of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2027, the Capacity Resource's Seasonal MRI Capacity and Monthly MRI Capacity calculated pursuant to Section III.15.3 shall be used for purposes of the Seasonal Capacity Auctions, the Monthly Reconfiguration Auctions, and the monthly trading activities associated with Capacity Commitment Periods occurring between June 1, 2028 and April 30, 2031.

III.15.B.2. Qualified Capacity to Seasonal MRI Capacity Auction Demand Curves and Inputs Transition Rules.

Notwithstanding anything in Section III.15.1 to the contrary, for purposes of the Seasonal Capacity Auctions, the Monthly Reconfiguration Auctions, and the monthly trading activities associated with Capacity Commitment Periods occurring between June 1, 2028 and April 30, 2031, the requirements of Section III.15.1 shall be modified as specified in this Section III.15.B.2.

III.15.B.2.1. Auction Demand Curves and Inputs.

For purposes of Capacity Market administration, including development of the demand curves pursuant to Section III.15.1.1, conducting the Seasonal Capacity Auctions pursuant to Section III.15.4, and conducting Monthly Reconfiguration Auctions pursuant to Section III.15.5, all capacity demand parameters, including the Installed Capacity Requirement, Net Installed Capacity Requirement, Maximum Capacity Limit, Maximum Capacity Limit for Gas-Constrained Winter Capacity, Local

Sourcing Requirement, Capacity Transfer Limit, and system, zonal, and gas constrained winter capacity MRI values shall be expressed in terms of Transition Seasonal MRI Capacity, rather than in terms of Seasonal MRI Capacity as set forth in Section III.15.1.

III.15.B.2.2. Seasonal Demand Anchor Price and Conversion of Annual CONE and Net CONE. For purposes of determining the Seasonal Demand Anchor Price pursuant to Section III.15.1.1.5 and converting Annual CONE and Net CONE values pursuant to Section III.15.1.2, certain inputs to the formulas specified in those sections shall be modified as described below.

(a) "$rMRI_t$" and "$rMRI_{t-1}$" shall be the representative seasonal Relative MRI value of the representative resource, modified in accordance with subsections (i) through (iii) below. The weights in subsections (i) through (iii) shall be those applicable to the Capacity Commitment Period for which the respective value of $rMRI_t$ or $rMRI_{t-1}$ is calculated. For purposes of this Section III.15.B.2.2, the representative resource's Summer QC-to-MCap ratio and Winter QC-to-MCap ratio shall be calculated using the Qualified Capacity and summer Seasonal Maximum Capability or winter Seasonal Maximum Capability, as applicable, as specified in Section III.15.1.1.5(a).

i. For the Capacity Commitment Periods occurring between June 1, 2028 and April 30, 2029, the representative seasonal Relative MRI value of the representative resource shall equal the sum of one-fourth of the representative seasonal Relative MRI value of the representative resource (as calculated as described in Section III.15.1.1.5(a)) and three-fourths of the relevant Summer QC-to-MCap Ratio or Winter QC-to-MCap Ratio, as applicable.

ii. For the Capacity Commitment Periods occurring between May 1, 2029 and April 30, 2030, the representative seasonal Relative MRI value of the representative resource shall equal the sum of half of the representative seasonal Relative MRI value of the representative resource (as calculated as described in Section III.15.1.1.5(a)) and half of the relevant Summer QC-to-MCap Ratio or Winter QC-to-MCap Ratio, as applicable.

iii. For the Capacity Commitment Periods occurring between May 1, 2030 and April 30, 2031, the representative seasonal Relative MRI value of the representative resource shall equal the sum of three-fourths of the representative seasonal Relative MRI value of the representative resource (as calculated as described in Section III.15.1.1.5(a)) and one-

fourth of the relevant Summer QC-to-MCap Ratio or Winter QC-to-MCap Ratio, as applicable.

(b) $MRI_t(NICR_t)$ shall be expressed in terms of Transition Seasonal MRI Capacity.

(c) $MRI_{t-1}(NICR_{t-1})$ shall be expressed in terms of Transition Seasonal MRI Capacity.

III.15.B.3. Firm Gas Requirements Transition Rules.

For the 2028-2029, 2029-2030, and 2030-2031 Winter Capacity Commitment Periods, in addition to meeting the gas firming requirements for designated Firm Gas Capacity using a pipeline gas transportation arrangement that meets the provisions of Section III.15.2.1.6.2.1, or an LNG supply arrangement that meets the provisions of Section III.15.2.1.6.2.2, or a combination thereof, a resource may meet the gas firming requirements for designated Firm Gas Capacity by entering into and maintaining for the Gas Firming Period one or more North American Energy Standards Board ("NAESB") or International Swaps and Derivatives Association ("ISDA") Base Contracts (and Transaction Confirmations) for purchase of natural gas that meets the requirements specified in this Section III.15.B.3. Such NAESB and ISDA Base Contracts (and Transaction Confirmations) may be combined with pipeline gas transportation agreements that meet the provisions of Section III.15.2.1.6.2.1 and/or LNG supply arrangements that meet the provisions of Section III.15.2.1.6.2.2 to meet the gas firming requirements for designated Firm Gas Capacity, and any such pipeline gas transportation arrangements, LNG supply arrangements, and/or NAESB and ISDA Base Contracts (and Transaction Confirmations) used to meet the gas firming requirements for designated Firm Gas Capacity shall be referred to herein as the "contract(s)." Market Participants electing to satisfy the gas firming requirements for designated Firm Gas Capacity by entering into and maintaining a contract meeting the requirements of this Section III.15.B.3 will be subject to the same contract submission and affidavit requirements set forth in Section III.15.2.1.6.4.

(a) *Contract Quantity*. The contract(s) must provide the resource with gas supply for every day of the Gas Firming Period in a quantity of gas that is sufficient to permit the resource to generate at the Firm Gas Capacity MW quantity for 16 hours per day.

(b) *Delivery Point*. The contract(s) must provide for delivery of the contract quantity to the point on the main gas transportation line from which the resource takes gas service.

(c) *Service Type*. The contract(s) must provide the resource with gas supply on a firm basis that meets the requirements for "firm" service (with fixed or variable quantity) under the NAESB or ISDA Base Contract for Sale and Purchase of Natural Gas. Any such contract(s) may not include any limitations that would further restrict when natural gas can be called during a day beyond the North American Energy Standards Board Wholesale Gas Quadrant scheduling and nominations standards.

III.15.1. Auction Demand Curves and Other Auction Inputs.

III.15.1.1. ~~Annual~~ Seasonal Capacity Auction Demand Curves.

The total amount of capacity cleared in the ~~Annual~~ Seasonal Capacity Auction pursuant to Section III.15.4 shall be determined using the System-Wide Capacity Demand Curve, ~~and~~ the Capacity Zone Demand Curves for the Capacity Zones modeled for the ~~Annual~~ Seasonal Capacity Auction, and for the Winter Capacity Auction, the Gas-Constrained Winter Capacity Demand Curve. The System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves described in this Section III.15.1.1 shall be shifted horizontally to the right by the amount of Seasonal MRI Capacity of Passive Demand Capacity Resources that have qualified Seasonal MRI Capacity in the relevant Capacity Zone or system-wide, as applicable, for the Capacity Commitment Period.

For purposes of Capacity Market administration, including development of the demand curves pursuant in this Section III.15.1.1, conducting the Seasonal Capacity Auctions pursuant to Section III.15.4, and conducting Monthly Reconfiguration Auctions pursuant to Section III.15.5, all Capacity Market parameters, including, but not limited to, the Installed Capacity Requirement, Net Installed Capacity Requirement, Maximum Capacity Limit, Local Sourcing Requirement, and system and zonal MRI values shall be expressed in terms of Seasonal MRI Capacity.

III.15.1.1.1. System-Wide Capacity Demand Curve.

The System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact values, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.15.1.1.~~4~~5. For any system capacity quantity greater than 110% of the Net Installed Capacity Requirement ~~(net of HQICCs)~~, the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Capacity Auction Offer Price Cap.

III.15.1.1.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact values, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.15.1.1.~~4~~5. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the truncation point, which is the amount of capacity for

which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Capacity Auction Offer Price Cap.

III.15.1.1.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact values, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.15.1.1.~~4~~5. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.15.1.1.4. Gas-Constrained Winter Capacity Demand Curve

The gas-constrained winter capacity Marginal Reliability Impact values calculated pursuant to Section III.12.2.3.3 shall be converted to quantities of Seasonal MRI Capacity using the capacity weighted average Relative MRI of all resources included in the calculation and subject to the Gas Availability Constraint. Once converted, the Gas-Constrained Winter Capacity Demand Curve shall specify a price for all quantities of gas-fired resource capacity without firm fuel arrangements based on the product of the Gas Availability Constraint's Marginal Reliability Impact value and the scaling factor specified in Section III.15.1.1.5. The prices specified by the Gas-Constrained Winter Capacity Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Gas-Constrained Winter Capacity Demand Curve specifies a price of negative $0.01/kW-month, the Gas-Constrained Winter Capacity Demand Curve shall specify a price of zero.

III.15.1.1.~~4~~5. Seasonal Demand Anchor Price and Capacity Demand Curve Scaling Factor.

For each Seasonal Capacity Auction, the ISO shall determine a Seasonal Demand Anchor Price and a capacity demand curve scaling factor as described in this Section III.15.1.1.5.

(a) The ISO shall determine a Seasonal Demand Anchor Price, expressed in $/kW-month, which shall be the annual Net CONE described in Section III.15.1.2 converted into seasonal values based on a representative resource's MRI Capacity assuming a constant capacity demand curve scaling factor

described in this Section III.15.1.1.5(b) on a rolling annual basis. The Seasonal Demand Anchor Price shall be determined in accordance with the following formula:

$$SDAP_t = Net\ CONE \times \frac{MRI_t(NICR_t)}{0.5 \times \left(rMRI_t \times \frac{MCap_t}{QC} \times MRI_t(NICR_t) + rMRI_{t-1} \times \frac{MCap_{t-1}}{QC} \times MRI_{t-1}(NICR_{t-1})\right)}$$

Where:

Representative resource = a simple cycle dual-fuel resource with a summer Seasonal EFORd and a winter Seasonal EFORd of 9%;

t = the Capacity Commitment Period associated with the Seasonal Capacity Auction for which the Seasonal Demand Anchor Price is being determined;

t-1 = the Capacity Commitment Period immediately preceding the Capacity Commitment Period associated with the Seasonal Capacity Auction for which the Seasonal Demand Anchor Price is being determined, except that for the Capacity Commitment Period beginning on June 1, 2028, all t-1 values shall be calculated pursuant to the Initial Winter Parameters Study;

$SDAP_t$ = the Seasonal Demand Anchor Price for the Seasonal Capacity Auction for season t;

Net CONE = the Net CONE applicable to the Seasonal Capacity Auction for which the Seasonal Demand Anchor Price is being determined, as adjusted pursuant to Section III.15.1.2.1(a);

$MCap_t$ and $MCap_{t-1}$ = For purposes of this Section III.15.1.1.5 and Section III.15.1.2.1(b), the representative resource shall be assigned a summer Seasonal Maximum Capability of 353.2 MW and a winter Seasonal Maximum Capability of 383.2 MW;

QC = For purposes of this Section III.15.1.1.5 and Section III.15.1.2.1(b), the representative resource type shall be assigned a summer and winter Qualified Capacity of 350.7 MW;

$rMRI_t$ and $rMRI_{t-1}$ = the representative seasonal Relative MRI value of the representative resource, calculated in the manner described in Section III.15.3.2(a)(i)(2) for a Generating Capacity Resource Without Energy Limitations that is not included in the resource adequacy assessment process addressed in Section III.12, using the Seasonal Maximum Capability and Seasonal EFORd values specified in this Section III.15.1.1.5(a);

$MRI_t(NICR_t)$ and $MRI_{t-1}(NICR_{t-1})$ = the Marginal Reliability Impact at the Net Installed Capacity Requirement, calculated pursuant to Section III.12.1.1 for seasons t and t-1.

~~(a)~~(b) The capacity demand curve scaling factor shall be set at the value such that, at the quantity specified by the seasonal System-Wide Capacity Demand Curve calculated pursuant to Section III.15.1.1.1 at the Seasonal Demand Anchor Price~~a price of Net CONE~~, the Loss of Load Expectation equals the Seasonal LOLE Target~~.1 days per year~~.

III.15.1.2. Capacity Auction Offer Price Cap and the Cost of New Entry.

III.15.1.2.1. Calculation of Capacity Auction Offer Price Cap, CONE, and Net CONE.

(a) ~~The Capacity Auction Offer Price Cap shall be the greater of (i) 1.6 multiplied by Net CONE; and (ii) CONE. References in this Section III.15 and Sections III.A.21 and III.A.24 to the Capacity Auction Offer Price Cap shall mean the Capacity Auction Offer Price Cap for the Annual Capacity Auction associated with the relevant Capacity Commitment Period.~~

~~(b)~~ To determine the CONE and Net CONE for the Seasonal~~Annual~~ Capacity Auctions associated with the Capacity Commitment Period beginning on June 1, 2028 and the subsequent Capacity Commitment Periods beginning on November 1, 2028, May~~June~~ 1, 2029, and November 1, 2029, the ISO shall make interim-year adjustments as described in Section III.15.1.2.2 to the following CONE and Net CONE calculated for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025:

(i) CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 was $12.400/kW-month.

(ii) Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 was $7.468/kW-month.

(b) Annual CONE and Net CONE values for the Seasonal Capacity Auctions associated with the Capacity Commitment Period beginning on June 1, 2028, and the subsequent Capacity Commitment Periods beginning on November 1, 2028, May 1, 2029, and November 1, 2029, shall be converted to values expressed in MRI Capacity by first converting annual CONE and Net CONE to seasonal values in $/kW-month of MRI Capacity using the summer and winter MRI Capacity of the representative resource defined pursuant to Section III.15.1.1.5(a), then averaging the two values.

i. The converted CONE value shall be determined in accordance with the following formula:

$$0.5 \times \frac{FCA\ CONE}{rMRI_t \times \frac{MCap_t}{QC}} + 0.5 \times \frac{FCA\ CONE}{rMRI_{t-1} \times \frac{MCap_{t-1}}{\text{QC}}}$$

ii. The converted Net CONE value shall be determined in accordance with the following formula:

$$0.5 \times \frac{FCA\ Net\ CONE}{rMRI_t \times \frac{MCap_t}{QC}} + 0.5 \times \frac{FCA\ Net\ CONE}{rMRI_{t-1} \times \frac{MCap_{t-1}}{\text{QC}}}$$

(c) Not later than the date on which the demand curves are filed pursuant to Section III.12.3, the ISO shall publish the summer and winter Relative MRI and MRI Capacity values of the representative resource.

(d) The Capacity Auction Offer Price Cap shall be the greater of (i) 1.6 multiplied by the converted values of Net CONE; and (ii) the converted value of CONE. References in this Section III.15 and Sections ~~III.A.21 and III.A.24~~ to the Capacity Auction Offer Price Cap shall mean the Capacity Auction Offer Price Cap for the Seasonal~~Annual~~ Capacity Auction associated with the relevant Capacity Commitment Period.

(e) The ISO shall recalculate CONE and Net CONE for the Seasonal~~Annual~~ Capacity Auction for the Capacity Commitment Period beginning on May~~June~~ 1, 2030. Thereafter, CONE and Net CONE shall be recalculated no less often than once every four years. The values of the representative resource specified in Section III.15.1.1.5 (a) shall be revised only in connection with a recalculation of CONE and Net CONE pursuant to this Section III.15.1.2.1(e). Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders, and the new values will be filed with the

Commission prior to the SeasonalAnnual Capacity Auction in which the new value is to apply. Notwithstanding the foregoing, the ISO may propose a different methodology to be used for the Capacity Commitment Period beginning on May 1, 2030, and each Seasonal Capacity Auction thereafter.

III.15.1.2.2. Interim-Year Adjustments to CONE and Net CONE.

(a) For years in which no full recalculation is performed pursuant to Section III.15.1.2.1(e), CONE and Net CONE shall be adjusted annually,for each Annual Capacity Auction with the following updates to the capital budgeting model used to calculate the CONE and Net CONE values set forth above in this Section III.15.1.2:

(1) Each line item associated with capital costs that is included in the capital budgeting model shall be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114).

(2) For each line item in (1) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the CONE and Net CONE values set forth in Section III.15.1.2.1. The value of each line item associated with capital costs in the capital budgeting model will be adjusted by the relevant multiplier.

(3) The energy and ancillary services offset values in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE, for each month of the Capacity Commitment Periods to which the updated value will apply.

(4) The annual adjustment to CONE and Net CONE for the SeasonalAnnual Capacity Auction for the Capacity Commitment Period beginning June 1, 2028, shall use a cost of debt of 6.85% and a cost of equity of 13.80%. These values shall also be used for the SeasonalAnnual Capacity Auction for the Capacity Commitment Periods beginning on November 1, 2028, MayJune 1, 2029, and November 1, 2029.

(5) If any of the values required for the calculations described in this Section III.15.1.2.2 are unavailable, then comparable values, prices or sources shall be used.

(b) The CONE and Net CONE values adjusted pursuant to this Section III.15.1.2.2 will be published on the ISO's website.

III.15.1.3. External Interface Capacity Import Capability and Capacity Transfer Limit

For each external interface, the Capacity Import Capability calculated pursuant to Section III.12.9.2.4 shall be converted to quantities of Seasonal MRI Capacity by multiplying the Capacity Import Capability by the Relative MRI calculated pursuant to Section III.12.2.4.

For each external interface, the Capacity Transfer Limit shall be calculated as the difference between the interface's Capacity Import Capability in quantities of Seasonal MRI Capacity minus the tie benefits of the applicable interface calculated pursuant to Section III.12.9. The Capacity Transfer Limit of an interface shall not be less than zero.

III.15.1.4. HQ Interconnection Capability Credit (HQICC)

The tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF specified in Section III.12.9.7 shall be the HQICC value that is applied for all purposes specified in Section III.15 except that if the Capacity Import Capability of the HQ Phase I/II HVDC-TF interface in quantities of Seasonal MRI Capacity calculated pursuant to Section III.15.1.3 is less than the interface's tie benefit value, then the HQICC value shall be limited to the value of Capacity Import Capability of the HQ Phase I/II HVDC-TF interface in quantities of Seasonal MRI Capacity calculated pursuant to Section III.15.1.3.

III.15.2. Capacity Resource Qualification.

Each resource, or portion thereof, must qualify as a Generating Capacity Resource, an Import Capacity Resource, a Demand Capacity Resource, or a Distributed Energy Capacity Resource. Each resource must ~~be~~ have a Seasonal MRI Capacity of at least 100 kW in size in the relevant season to participate in a~~n Annual~~ Seasonal Capacity Auction~~, except for resources registered with the ISO prior to the earliest date that any portion of Section III.13 became effective~~. The summer period of a Capacity Resource's Seasonal ~~Qualified~~ MRI Capacity ~~Values~~ shall be the months of ~~June~~ May through ~~September~~ October and the winter period shall be the months of ~~October~~ November through ~~May~~April~~, except in the case of Demand Capacity Resources, where the summer period shall be the months of April through November and the winter period shall be the months of December through March~~.

This Section III.15.2 details the requirements of the qualification process for the ~~Annual~~ Seasonal Capacity Auction, as well as certain requirements related to Monthly Reconfiguration Auctions and Capacity Supply Obligation Bilateral transactions. Data submission and demonstration requirements for resources that have never previously ~~counted~~ participated as capacity and seek to qualify to participate in a~~n~~ Seasonal~~Annual~~ Capacity Auction, are set forth in Section III.15.2.1. Data submission and demonstration requirements for resources that have never previously ~~counted~~ participated as capacity and seek to qualify to participate in a Monthly Reconfiguration Auctions or bilateral trading activities are set forth in Section III.15.2.2. Qualification requirements with respect to interconnection service are addressed in Section III.15.2.3. Qualification requirements with respect to resources that have previously counted as capacity and have materially changed are addressed in Section III.15.2.4. Following the Seasonal~~Annual~~ Capacity Auction's Qualification Data Submission Deadline, the ISO calculates and provides to Lead Market Participants Advisory ~~Qualified~~ MRI Capacity Values for each Capacity Resource, per Section III.15.2.5. Lead Market Participants then have until the Capacity Demonstration Deadline to demonstrate that their Capacity Resources have achieved Commercial Operation, per Section III.15.2.6~~. Thereafter, the ISO calculates Seasonal Qualified Capacity Values for each Capacity Resource, per Section III.15.2.7, which values are subject to the challenge process addressed therein. Lead Market Participants are then permitted to submit Composite Offers in accordance with Section III.15.2.8., and l~~ Load serving entities are permitted to submit self-supply designations in accordance with III.15.2.7~~9~~. Lead Market Participants associated with a Capacity Resource experiencing an Unexpected Full Forced Outage of the entire resource with an expected duration encompassing an entire Capacity Commitment Period may reduce its Seasonal MRI Capacity to zero for the duration of the Capacity Commitment Period in in accordance with Section III.15.2.8 Final ~~Qualified~~ Seasonal MRI Capacity values~~-~~ for each Capacity Resource are ~~calculated~~ published to Lead Market Participants by the

ISO no less than one Business Day prior to the opening of the ~~Annual~~ Capacity Auction Offer Window in accordance with Section III.15.2.~~10~~9. Monthly MRI Capacity values for each Capacity Resource are published to Market Participants in accordance with Section III.15.2.10. The publication of offer information during the qualification process and after ~~the~~ each ~~Annual~~ Seasonal Capacity Auction is addressed in Section III.15.2.11.

Resources seeking to qualify for a~~n Annual~~ Seasonal Capacity Auction may be subject to buyer-side market power review and mitigation pursuant to Section III.A.21 and must abide by the applicable submission requirements and timelines set forth therein prior to seeking to qualify for a~~n Annual~~ Seasonal Capacity Auction. To the extent not already established for the purposes of the submission requirements of Section III.A.21.1.5, all capacity suppliers seeking to qualify for a~~n Annual~~ Seasonal Capacity Auction must be Market Participants prior to the Qualification Data Submission Deadline.

The Lead Market Participant for a resource participating in a~~n Annual~~ Seasonal Capacity Auction ~~may~~ shall not change during the period beginning 15 Business Days prior to the opening of ~~the~~ each ~~Annual~~ Capacity Auction Offer Window and ending with the posting of the results of the corresponding ~~Annual~~ Seasonal Capacity Auction.

III.15.2.1. Qualification Data Submission Requirements.

III.15.2.1.1. Qualification Data Submission Package.

(a) For a resource that has not previously received a Capacity Supply Obligation in a~~n Annual~~ Seasonal Capacity Auction or Forward Capacity Auction, or that is treated as if it had not pursuant to Section III.15.2.4 or Section III.15.2.1.1.1**,** to qualify as a Capacity Resource for participation in a~~n Annual~~ Seasonal Capacity Auction, a Lead Market Participant must submit the following information to the ISO, as applicable by resource type, by the Qualification Data Submission Deadline, unless otherwise specified~~, as applicable~~:

(a) the resource name;

(b) the Lead Market Participant's contact information, including any relevant technical, credit/financial, or other contacts to be included in communications with the ISO relating to the resource;

(c) the resource type, technology type, and fuel type;

(d) the load zone of the resource;

~~(b)~~

(e) the estimated Maximum Capability (or equivalent) of the resource;

~~(c)~~(f) the date by which the resource is expected to complete its capacity demonstration pursuant to III.15.2.6(c) ~~or to update its as-built data pursuant to III.15.2.6(d)~~;

~~(d) the resource address or location, and if available, asset identification number;~~

(g) whether the resource has ever previously ~~had~~ held a Capacity Supply Obligation and, if so, the asset identification number(s) associated with the resource and, if submitting a material change pursuant to Section III.15.2.4.1, an estimate of any incremental change in Maximum Capability (or equivalent) associated with the resource and the date of the change;

(h) for Demand Capacity Resources, the resource subtype, measure type(s), net supply capability, and resources other than those composed of Energy Efficiency, a maximum facility load;

~~(e)~~(i) for resources other than Demand Capacity Resources, whether the resource is a settlement-only resource or Intermittent Power Resource;

~~(f) the location of the resource's interconnection;~~

~~(g) the estimated Seasonal Qualified Capacity Values of the resource, as well as an estimate of any incremental Seasonal Qualified Capacity Values (in MW) (for Generating Capacity Resources and Import Capacity Resources);~~

~~(h) the estimated total summer and winter demand reduction value (for Demand Capacity Resources and Distributed Energy Capacity Resources) or net injection capability values per facility (for Distributed Energy Capacity Resources);~~

~~(i)~~(j) ~~a description of the resource, including (for Generating Capacity Resources and Import Capacity Resources) a general description of the resource's equipment configuration and a description of the resource technology type, and (for Demand Capacity Resources) a description of the resource's Demand Capacity Resource type and measure type, and (for Distributed Energy Capacity Resources) a description of the project and its configuration, including the types of generation and demand response composing the project, and (for Generating Capacity Resources and Distributed Energy Capacity Resources comprising generation) a one-line diagram of the resource's configuration;~~for Intermittent Power Resources, the additional resource-specific technical data requirements necessary to develop a generating profile of such resources;

(k) for Hybrid Generating Capacity Resources, resource and asset identification numbers, any co-located Hybrid Generating Capacity Resources behind the same point of interconnection along with their resource and asset identification numbers, a one-line

diagram of the hybrid facility's resource's configuration, facility limit, Seasonal MRI Capacity allocation percentages, capability scaling allocation percentages, storage capability, grid charging capability, round trip efficiency, an indication of configuration-type based on one of the following categories: (1) multiple Capacity Resource, no facility limitation, (2) multiple Capacity Resource, facility limitation, (3) single Capacity Resource, non-intermittent, or (4) single Capacity Resource, intermittent;

~~(j)~~(l) for resources supported by an ~~Internal~~ Elective Transmission Upgrade, ~~all unique project identifiers~~whether any Import Capacity Resources are associated with the ~~Internal~~ Elective Transmission Upgrade;

~~(k)~~(m) for Generating Capacity Resources with a contract to export capacity from the New England Control Area during the Capacity Commitment Period, ~~the interface over which the capacity will be exported and~~ the contract associated with the export capacity;

~~(l)~~(n) Additional requirements for Import Capacity Resources, the interface over which the capacity will be imported and one of the following submissions documenting the source of the imported capacity, as further detailed in Section III.15.2.1.1.1: (i) documentation of a contract entered into before the Qualification Data Submission Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for ~~one or more years encompassing~~ the duration of the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iii) documentation for system-backed import capacity that the Import Capacity Resource will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load~~.~~;

~~(m)~~(o) Additional requirements for Demand Capacity Resources, as further detailed in Section III.15.2.1.1.2: ~~resource technical and credit/financial contacts;~~ Measurement and Verification Plan (for ~~On-Peak Demand~~Passive Demand Capacity Resources composed of Energy Efficiency ~~or Seasonal Peak Demand Capacity Resources~~); ~~Load Zone~~ and Dispatch Zone (for Active Demand Capacity Resources);

~~(n)~~(p) Additional requirements for Distributed Energy Capacity Resources, as further detailed in Section III.15.2.1.1.3: ~~expected nameplate capacity by technology type per facility; installation date of facilities that are part of the project and already constructed, installed,~~

~~or in commercial operation; indication of whether the project elects Intermittent Power Resource treatment~~; ~~resource technical and credit/financial contacts; Load Zone,~~the Distributed Energy Resource Aggregation type(s), ~~-~~Dispatch Zone, and DRR Aggregation Zone;

(q) Additional requirements for resources with capacity impacted by ambient air conditions between 90 degrees and 100 degrees, as further detailed in Section III.15.2.1.5; and

~~(o)~~

~~(p) Additional requirements for resources seeking ISO-estimated Seasonal Qualified Capacity Values, as further detailed in III.15.2.6(d): the Qualification Data Submission Package shall satisfy the technical data requirements associated with such resources and be supplemented with the as-built status of the resource on the date of the relevant Capacity Demonstration Deadline~~Additional requirements for resources seeking to qualify their firm fuel capacity in advance of a Winter Capacity Auction, as further detailed in Section III.15.2.1.6; and~~.~~

(r)

(s) Additional Requirements for those Capacity Resources or Assets of the same technology type that are subject to an output limitation based upon the interdependence of common elements with at least one other Capacity Resource or Asset: the Assets or Capacity Resources subject to the common limiting element, the (MW) output limitation of the common limiting element, and documentation sufficient to verify such output limitation.

(b) By submitting the required qualification information, the Lead Market Participant certifies that a Capacity Offer from the resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 of Section II of the Tariff.

(c) The ISO may waive the submission of any information not required for evaluation of the resource.

III.15.2.1.1.1. Additional Import Capacity Resource Requirements.

Import Capacity Resources must be backed by one or more External Resources or by an external Control Area for the duration of the relevant Capacity Commitment Period. A resource located in an external Control Area that, if located in the New England Control area, would be classified for the purposes of Section III.15.3 as a Demand Capacity Resource, Generating Capacity Resource that is an Intermittent Power Resource, Energy Storage Generating Capacity Resource, Distributed Energy Capacity Resource,

or a Hybrid Capacity Resource composed of any such resource types ~~An external demand resources may not be~~shall be ineligible to qualify as an ~~I~~Import Capacity Resource backed by an External Resource. External nodes shall be established and mapped to Capacity Zones pursuant to the provisions in Attachment K to Section II of the Transmission, Markets and Services Tariff. For the purposes of the qualification process described in this Section III.15.2, all Import Capacity Resources shall be treated as if they had never previously participated as capacity and must submit the materials described pursuant to this Section III.15.2.1.1 for each Capacity Commitment Period for which the Import Capacity Resource seeks to qualify capacity. Import Capacity Resources ~~backed by an~~ located in or crossing an ~~E~~external Control Area that does not have an Operating or Coordination Agreement with the ISO shall be ineligible to participate in the ~~Annual~~ Capacity Market. No single Import Capacity Resource may qualify capacity in excess of the ~~external interface~~ Capacity Transfer ~~l~~Limits as described in Section III.15.1.3~~2.10~~.

An Elective Transmission Upgrade with Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall have its external node modeled in the ~~Annual~~ Seasonal Capacity Auction after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the ~~Annual~~ Seasonal Capacity Auction qualification requirements of this Section III.15.2.1 and demonstration requirements of III.15.2.6. The ~~Qualified~~ Seasonal MRI Capacity of all Import Capacity Resources associated with an Elective Transmission Upgrade shall not exceed the Elective Transmission Upgrade's Capacity Network Import Capability.

Capacity Offers for Import Capacity Resources shall be subject to rationing except for Capacity Offers priced above the Capacity Offer Price Threshold for Import Capacity ~~r~~Resources associated with an Elective Transmission Upgrade, which must obtain a Capacity Supply Obligation or not in whole unless the Capacity Offer indicates~~d~~ that it may be rationed as described in III.15.4.1.

III.15.2.1.1.1.1. Imports Backed by External Resources.

If the Import Capacity Resource will be backed by one or more External Resources, the Lead Market Participant shall submit a requested Seasonal MRI Capacity and a description of how the Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify. The description must indicate specifically which External Resources will back the Import Capacity Resource during the Capacity Commitment Period and contain the relevant historical performance data for each resource~~.~~, including (1) the Seasonal EFORd, (2) the Seasonal Maximum Capability equivalent, and (3) for those External Resources that maintain stored fuel inventories, the

Seasonal Qualified Inventory equivalent of the External Resource. The Seasonal EFORd shall be consistent with the Seasonal EFORd described in Section III.12.7.3.3. The Seasonal Maximum Capability equivalent of the Import Capacity Resource shall be the maximum hourly demonstrated performance during the current month and preceding 36 calendar months at the time of qualification, occurring during the seasonally-specific conditions described in Section III.1.5.5.1. The Seasonal Qualified Inventory equivalent shall be calculated as a function of (1) the average of the median fuel inventory levels of the External Resource(s) from the prior three like-seasons (summer or winter) and (2) the resource's heat rate or turbine efficiency. For those Import Capacity Resources backed by one or more External Resource(s) that are gas-only or dual-fuel and elect to qualify using gas capability in a Winter Capacity Auction, the Lead Market Participant must, prior to the relevant Capacity Demonstration Deadline, submit information to demonstrates that the gas-only or dual-fuel resources will have pipeline access upstream of a liquid receipt point or contractual arrangements for gas transportation for the external resource. If those External Resources are not owned or controlled directly by the Lead Market Participant, the description must include a commitment that the External Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met. The Lead Market Participant associated with an Import Capacity Resource backed by one or more External Resources shall include in its Qualification Data Submission Package an affidavit executed by a corporate officer attesting to the accuracy of its content and that: (1) the External Resource is interconnected to deliver capacity in its native Control Area; and (2) that the External Resource is deliverable for 16 hours during each day of the Capacity Commitment Period at its requested Seasonal MRI Capacity, consistent with supporting data provided by the Capacity Demonstration Deadline for that Capacity Commitment Period.

III.15.2.1.1.1.2. Imports Backed by an External Control Area.

If the Import Capacity Resource will be backed by an external Control Area, the Lead Market Participant shall submit a requested Seasonal MRI Capacity based on: (1) system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the Import Capacity Resource; and (2) historical system load and capacity data for the three preceding like-seasons. The submitted data shall be used to determine the Seasonal Maximum Capability equivalent and Historical Forecast Performance Factor of the Import Capacity Resource. The Seasonal Maximum Capability equivalent of the Import Capacity Resource shall be the forecast excess capacity (available supply, less obligations) in the external Control Area during the peak load hour of the month with the least excess capacity during the relevant Capacity Commitment Period. The Historical Forecast

Performance Factor of the Import Capacity Resource shall be a three-year moving average, using only like-season historical data, of the ratio of: (1) the sum of actual excess capacity (available supply, less obligations), capped at Seasonal Maximum Capability equivalent, during each hour of a season in the external Control Area; and (2) the sum of the Seasonal Maximum Capability equivalent in the external Control Area during each hour of that season. If the submitted data is insufficient to determine a Historical Forecast Performance Factor using a three-year moving average of like-season historical data, then the moving average of like-season historical data shall be based on the number of seasons available. If no full season of like-season historical data during the most recent three like-seasons is available, the Historical Forecast Performance Factor shall be set at 0.80. The Seasonal MRI Capacity of all Import Capacity Resources qualified by a Lead Market Participant that qualifies an Import Capacity Resource backed by an external Control Area shall not exceed the product of the Seasonal Maximum Capability equivalent and Historical Performance Factor of the external Control Area as described in this Section III.15.2.1.1.1.2. The Lead Market Participant associated with an Import Capacity Resource backed by an external Control Area shall include in its Qualification Data Submission Package an affidavit executed by a corporate officer attesting to the accuracy of its content, that the Lead Market Participant has been authorized to export Capacity to the New England Control Area on behalf of the external Control Area, and that the external Control Area will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.15.2.1.1.1.3. Imports Crossing Intervening Control Areas.

Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) for imports crossing a single intervening Control Area, the Lead Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the Qualification Data Submission Deadline, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing; (2) for imports crossing more than one intervening Control Area, in addition to the requirements above, the Lead Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the Qualification Data Submission Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads,

and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load; and (3) the Lead Market Participant entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load. The Lead Market Participant associated with an Import Capacity Resource crossing an intervening external Control Area shall include in its Qualification Data Submission Package an affidavit executed by a corporate officer attesting to the accuracy of its content and consistency with this Section III.15.2.1.1.1.3.

III.15.2.1.1.2. Additional Demand Capacity Resource Requirements.

A Demand Capacity Resource may be an Active Demand Capacity Resource or a Passive Demand Capacity Resource, either as an On-Peak Demand Capacity Resource~~,~~ or Seasonal Peak Demand Capacity Resource~~., and~~ A Demand Capacity Resource may include an end-use customer facility with a Net Supply Capability of 5 MW or more only if the facility's Net Supply Capability does not exceed its Maximum Facility Load. Demand Capacity Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Capacity Resource. Demand Capacity Resources are not permitted to submit a Capacity Offer to import into or export out of the New England Control Area.

~~For a resource, or portion thereof, that never previously obtained a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction to qualify as an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource for the Capacity Commitment Period beginning June 1, 2028, the measure or measures contained in the resource must not have been in-service prior to June 1, 2024. For a resource, or portion thereof, that never previously obtained a Capacity Supply Obligation in a Forward Capacity Auction or Annual Capacity Auction to qualify as~~ For a measure to be included in a Passive Demand Capacity Resource~~n On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource in the Annual Capacity Auction or Monthly Reconfiguration Auction, as relevant, for or~~ during the Capacity Commitment Period beginning June 1, ~~2029~~2028, and all Capacity Commitment Periods thereafter, the measure ~~or measures contained in the resource~~ must have been registered with the ISO within 18 months of being placed in-service ~~or previously qualified as capacity no more than six months before the prior Annual Capacity Auction's Capacity Demonstration Deadline~~.

III.15.2.1.1.2.1. Measurement and Verification of Passive Demand Capacity Resources Composed of Energy Efficiency.

(a) To demonstrate the demand reduction value of a~~n On-Peak~~ Passive Demand Capacity Resource composed of Energy Efficiency ~~or Seasonal Peak Demand Capacity Resource~~, the Lead Market Participant of such a resource participating in the ~~Annual~~ Seasonal Capacity Auction, Capacity Supply Obligation Bilaterals, or Monthly Reconfiguration Auctions shall submit to the ISO Measurement and Verification Documents in accordance with this Section III.15.2.1.1.2.1 and the ISO New England Manuals. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.15.2.1.1.2.1 and the ISO New England Manuals.

(b) Measurement and Verification Documents must demonstrate both availability and performance of a~~n On-Peak Demand Capacity Resource or Seasonal Peak~~ Passive Demand Capacity Resource in reducing demand coincident with the Demand Resource On-Peak Hours of an On-Peak Demand Capacity Resource or the Demand Resource Seasonal Peak Hours of a Seasonal Peak Demand Resource such that the reported monthly demand reduction value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manuals and ISO New England Operating Procedures. The Measurement and Verification Documents shall: (1) serve as the basis for the claimed demand reduction value of an ~~On-Peak Demand Capacity Resource or Seasonal Peak~~ Passive Demand Capacity Resource; (2) document the measurement and verification performed to verify the achieved demand reduction value of the ~~On-Peak Demand Capacity Resource or Seasonal Peak~~Passive Demand Capacity Resource; and (3) contain a projection of the ~~On-Peak Demand Capacity Resource's or Seasonal Peak~~ Passive Demand Capacity Resource's demand reduction value for each month of the Capacity Commitment Period and ~~, for those Demand Capacity Resources composed of energy efficiency measures,~~ over the expected Measure Lives. A~~n On-Peak~~ Passive Demand Capacity Resource's ~~or Seasonal Peak Demand Capacity Resource's~~ Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction ~~or output~~ during Demand Resource On-Peak Hours for an On-Peak Demand Capacity Resource or Demand Resource Seasonal Peak Hours for a Seasonal Peak Demand Capacity Resource. ~~If an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource includes Distributed Generation, the Measurement and Verification Documents must describe the individual metering or metering protocol used to monitor and verify the output of the Distributed Generation, consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals.~~

(c) The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the ~~Annual Capacity Auction~~ qualification process, as described in this Section III.15.2.1.1.2.1, and monthly Measurement and Verification data submitted during the Capacity Commitment Period. The monthly Measurement and Verification data shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan. Such monthly Measurement and Verification data shall document the Lead Market Participant's total demand reduction value from both eligible pre-existing measures and new measures, and the Lead Market Participant's total demand reduction value from both eligible pre-existing measures and new measures, for all measures in operation as of the end of the previous month. The monthly Measurement and Verification data shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Lead Market Participants. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

(d) Lead Market Participants for ~~On-Peak Demand Capacity Resources and Seasonal Peak~~Passive Demand Capacity Resources composed of Energy Efficiency shall submit no less frequently than once per year following the initial Section III.15.2.1.1.2.1 submission, a statement certifying that the Passive Demand Capacity Resource for which the Lead Market Participant is requesting compensation continues to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than ten Business Days before the Winter Capacity Auction Qualification Data Submission Deadline.

(e) For ~~On-Peak Demand Capacity Resources and Seasonal Peak~~ Passive Demand Capacity Resources comprising customer facilities with greater than or equal to 10 kW of demand reduction value per facility, Lead Market Participants shall maintain records of retail customers served, including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly demand reduction values. For ~~On-Peak Demand Capacity Resources and Seasonal Peak~~Passive Demand Capacity Resources targeting customer facilities with under 10 kW of demand reduction value per facility, the Lead Market Participant shall maintain records as described above for customer facilities with greater than or equal to 10 kW of demand reduction value per facility, or shall maintain records of aggregated demand reduction values and measures installed by Load Zone and meter domain. Lead Market Participants shall maintain such records

until the end of the Measure Life, or until the Passive Demand Capacity Resource is retired or deactivated from the ~~Annual~~ Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

(f) The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the ~~Annual~~ Seasonal Capacity Auction qualification process as described in Section III.15.2 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Lead Market Participant to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

(g) For a Passive Demand Capacity Resource that consists of Energy Efficiency, a Seasonal Maximum Capability equivalent shall be determined for each residential-sector and commercial-sector end use combination that constitute the Passive Demand Capacity Resource. The Seasonal Maximum Capability equivalent of each such sector and end use combination shall equal the resource's seasonal demand reduction value for the combination multiplied by the ratio of (1) the maximum demand reduction value to (2) the average demand reduction value during the relevant peak hours (Demand Resource Seasonal Peak Hours or Demand Resource On-Peak Hours) of the hourly profiles that reflect the expected hourly, system-wide demand reduction for the sector and end-use combination.

III.15.2.1.1.3. Additional Distributed Energy Capacity Resource Requirements.

(a) Distributed Energy Capacity Resources. A facility connected at a point of interconnection that is 5 MW or greater cannot be a part of a Distributed Energy Capacity Resource. A Distributed Energy Capacity Resource comprises one or more Distributed Energy Resource Aggregations located in a single Capacity Zone and a single DRR Aggregation Zone, except that (a) a Settlement Only Distributed Energy Resource Aggregation may not participate in a Distributed Energy Capacity Resource with any other type of Distributed Energy Resource Aggregation, and (b) an end-use customer facility participating as part of a~~n On-Peak Demand Capacity Resource or Seasonal Peak~~ Passive Demand Capacity Resource ~~with measures other than Energy Efficiency may~~ not participate in a Distributed Energy Capacity Resource.

Distributed Energy Capacity Resources are not permitted to submit a Capacity Offer to import into or export out of the New England Control Area. For purposes of this Section III.15.2.1.1.3: (i) if a facility is expected to interconnect at a point of interconnection, its net injection capability is the generation capability of the installed generation technology at the point of interconnection; (ii) if a facility is expected to interconnect at a Retail Delivery Point and does not plan to participate in the aggregation as a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation, the net injection capability is the lesser of the generation less the load profile measured at the location of the end-use customer meter or the amount the facility is contractually able to inject.

(b) Demand Response Resource in Distributed Energy Capacity Resources. If the Distributed Energy Capacity Resource includes Demand Response Resources, the completed Qualification Data Submission Package shall include the following additional information: the estimated summer and winter demand reduction values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses); the estimated total summer and winter demand reduction value of the Demand Response Resource (which must be consistent with the baseline calculation methodology in Section III.8.2); and supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated demand reduction values.

~~(c) Net Injection of 5 MW or Greater. If the Distributed Energy Capacity Resource contains a Distributed Energy Resource Aggregation with a facility with net injection of 5 MW or greater at a Retail Delivery Point, then the completed Qualification Data Submission Package for such a resource shall include the following additional information: the Pnode and service address at which the end-use facility is located; nameplate MW and net injection capability; non-coincident peak load (MW) of the facility without generation; technology type; and the Market Participant's portion of generation requested to be included as Qualified Capacity.~~

~~(d) Net Injection Greater Than or Equal to 1 MW and less than 5 MW. If the Distributed Energy Capacity Resource contains a Distributed Energy Resource Aggregation with a facility that has net injection capability at the point of interconnection of 1 MW or greater and less than 5 MW, then the completed Qualification Data Submission Package for such a facility shall include the following additional information: distribution bus; technology type; nameplate MW; one-line diagram of the plant and station facilities, including any known transmission facilities; if the facility is intermittent, the requested contribution of Qualified Capacity and supporting site-specific data; if an interconnection~~

~~agreement is required under state requirements, the date when the interconnection request was submitted and the status of that interconnection request.~~

III.15.2.1.2. Market Power Review.

Lead Market Participants seeking to qualify a Capacity Resource that has not previously obtained a Capacity Supply Obligation in a~~n Annual~~ Seasonal Capacity Auction or Forward Capacity Auction, or that is otherwise treated as if it had never done so pursuant to this Section III.15.2 or Section III.A.21, must comply with the market power review provisions of Section III.A.21 by the ~~Annual~~ Seasonal Capacity Auction Qualification Data Submission Deadline.

III.15.2.1.3. Capacity Commitment Period Election.

For the ~~Annual~~ Seasonal Capacity Auctions corresponding with the ~~for the 2028-2029, 2029-2030 and 2030-2031~~ Capacity Commitment Periods occurring between June 1, 2028 and October 30, 2031, a Lead Market Participant that has made the election in Section III.13.1.1.2.2.4 of the Forward Capacity Market rules with respect to a Capacity Resource must specify, by the Qualification Data Submission Deadline associated with the Capacity Commitment Period beginning June 1, 2028, or associated with the first Capacity Commitment Period of the Capacity Resource's expected Commercial Operation occurring thereafter, whether it elects to continue to have the associated Capacity Supply Obligation and Capacity Clearing Price apply in ~~Annual~~ Seasonal Capacity Auctions for the balance of the period permitted for such Capacity Resource pursuant to Section III.13.1.1.2.2.4, and in no case beyond May 31, 2031. Should a Lead Market Participant elect to terminate Section III.13.1.1.2.2.4 treatment for its Capacity Resource, it may not re-elect such treatment for any future ~~Annual~~ Seasonal Capacity Auctions.

A Lead Market Participant that has made the election in Section III.13.1.1.2.2.4 of the Forward Capacity Market rules with respect to a Capacity Resource which has not achieved Capacity Market Commercial Operation as defined in Section III.15.2.6 of Market Rule 1 ~~may~~ shall not participate in the ~~Annual~~ Seasonal Capacity Auction ~~for the 2028-2029 Capacity Commitment Period and~~ or ~~shall not~~ have the previously elected Capacity Supply Obligation and Capacity Clearing Price apply ~~for the 2028-2029~~unless it has achieved Capacity Market Commercial Operation by the Capacity Demonstration Deadline for the relevant Seasonal Capacity Auction ~~Capacity Commitment Period~~. ~~Should such resource achieve Capacity Market Commercial Operation in time for participation in the Annual Capacity Auction for the 2029-2030 Capacity Commitment Period, or the Annual Capacity Auction for the 2030-2031 Capacity Commitment Period, it may elect to have the Capacity Supply Obligation and Capacity Clearing Price it received pursuant to Section III.13.1.1.2.2.4 apply for the balance of the period permitted for such~~

~~Capacity Resource pursuant to Section III.13.1.1.2.2.4, and in no event after the Annual Capacity Auction for the 2030-2031 Capacity Commitment Period.~~

III.15.2.1.4. Material Deficiency in Data Submission.

In its review of a Lead Market Participant's data submission under this Section III.15.2.1, the ISO may consult with the Lead Market Participant~~,~~ to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO determines that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Lead Market Participant may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

In the event the ISO determines that a Lead Market Participant's data submission under Section III.15.2.1 is materially deficient, it shall notify the participant of such deficiencies at least ten Business Days prior to publication of the Advisory Seasonal ~~Qualified~~MRI Capacity Values, and the Lead Market Participant shall have five Business Days from the date of notification to cure the deficiencies. Should a Lead Market Participant fail to cure such deficiencies by the end of the cure period, it shall not be permitted to participate in the ~~Annual~~ Seasonal Capacity Auction. In the event of such a rejection, the ISO shall provide the Lead Market Participant with a written explanation of the reason for the rejection within ten Business Days of the close of the cure period.

III.15.2.1.5. Additional Qualification Requirements for Ambient Air Condition Impacts.

In the Qualification Data Submission Package or as part of a Capacity Offer submitted prior to the Capacity Offer Review Submission Deadline, a Lead Market Participant may submit documentation indicating that a portion of its resource's capacity will not be physically available due to an ambient air condition during the Summer Capacity Commitment Period. ~~The size of such ambient air condition is calculated as the difference between the summer Qualified Capacity at 90 degrees and the rating of the resource at 100 degrees.~~ The ISO shall verify during the qualification or Capacity Offer review process the size of the ambient air condition. The maximum allowable ambient air condition MW that will be physically unavailable in the Summer Capacity Auction shall be determined using the following formula:

Ambient air condition MW =
max(summer Seasonal MRI Capacity – Expected Output at 100 degrees, 0)

Where:
Summer Seasonal MRI Capacity = summer Relative MRI multiplied by the summer Seasonal Maximum Capability
Expected Output at 100°F = summer Seasonal Maximum Capability – (Rating at 90°F – Rating at 100°F)

III.15.2.1.6. Firm Gas Capacity Election Requirements.

A Generating Capacity Resource that is capable of operating on natural gas and that meets the requirements of this Section III.15.2.1.6 may elect to designate some or all of its capacity as Firm Gas Capacity in the Winter Capacity Auction. Such election, including all supporting materials specified in Section III.15.2.1.6.4, must be submitted to the ISO by the Capacity Demonstration Deadline for the Winter Capacity Auction. Prior to submittal, resources may request consultation with the ISO regarding such election, including, without limitation, consultation with respect to the quantity of Firm Gas Capacity subject to the election and with respect to whether the resource's pipeline gas or liquified natural gas contractual arrangements meet the firming requirements specified in this Section III.15.2.1.6.

Resources making an election under this Section III.15.2.1.6 must designate a quantity of Firm Gas Capacity in accordance with Section III.15.2.1.6.1. Designated Firm Gas Capacity must meet either the pipeline gas transportation firming requirements specified in Section III.15.2.1.6.2.1 or the liquefied natural gas firming requirements specified in Section III.15.2.1.6.2.2; these firming requirements must be met for the full duration of the Gas Firming Period. Resources that meet the pipeline gas transportation firming requirements are permitted to release firm transportation rights solely under the conditions specified in Section III.15.2.1.6.3. The ISO shall have the right to reject all or any portion of a Firm Gas Capacity designation that does not meet the requirements of this Section III.15.2.1.6. All requirements in this Section III.15.2.1.6 pertaining to Firm Gas Capacity are expressed in terms of MRI Capacity.

III.15.2.1.6.1. Quantity of Firm Gas Capacity Designation.

A resource making an election under Section III.15.2.1.6 must designate a quantity of Firm Gas Capacity, which may be equal to or less than the resource's MRI Capacity for the Winter Capacity Auction. In the event the resource designates a quantity of Firm Gas Capacity that is greater than the resource's MRI

Capacity for the Winter Capacity Auction, the resource's Firm Gas Capacity shall be capped at its MRI Capacity.

III.15.2.1.6.2. Gas Firming Requirements.

To meet the firming requirements for designated Firm Gas Capacity, a resource must enter into and maintain for the entire three-month duration of the Gas Firming Period a pipeline gas transportation arrangement that meets the provisions of Section III.15.2.1.6.2.1, or an liquified natural gas supply arrangement that meets the provisions of Section III.15.2.1.6.2.2, or a combination thereof.

III.15.2.1.6.2.1. Pipeline Gas Transportation Firming Requirements

A resource may satisfy the gas firming requirements for the designated Firm Gas Capacity by entering into a contract (one or more) for firm gas transportation service on one or more of the interstate gas transportation pipelines that meets the requirements of this Section III.15.2.1.6.2.1.

A resource may enter into a firm gas transportation contract directly with the pipeline or indirectly via a contract with a gas marketer, where such contract utilizes firm transportation service provided for under a gas transportation contract with the pipeline; provided that in either case the totality of the contractual arrangements (whether direct or indirect) meets the requirements specified in this Section III.15.2.1.6.2.1. For the avoidance of doubt, resources that meet the gas firming requirements via a firm gas transportation contract are not required to demonstrate or otherwise provide information on non-transportation-related gas supply arrangements.

(a) *Contract Quantity*. The firm gas transportation contract(s) (entered into directly or indirectly) must provide the resource with firm gas transportation for every day of the Gas Firming Period in a quantity of gas that is sufficient to permit the resource to generate at the Firm Gas Capacity MW quantity for 16 hours per day.

(b) *Firm Transportation Service Type*. The firm gas transportation contract(s) (entered into directly or indirectly) must provide the resource with firm transportation service that meets the definition of "service on a firm basis" under Part 284 of the Federal Energy Regulatory Commission's rules and regulations. Firm transportation service may be for either primary or secondary points of receipt and delivery, and must meet the receipt and delivery requirements set forth in sub-section (c) below. "No notice" firm transportation service is not required.

(c) *Receipt and Delivery Points.*

(i) *Receipt points, delivery points, and contract path terminology*. Two categories of receipt and delivery points are contemplated in this sub-section (c) for purposes of specifying the receipt and delivery point requirements:

(x) The "contract" receipt and delivery points, which are the receipt and delivery points identified in a firm gas transportation contract made directly with a pipeline, are used to define the contract path, as that term is defined below.

(y) The "required" receipt and delivery points, which establish geographic receipt and delivery criteria for a resource's firm transportation service. The required delivery point is the point on the mainline from which the resource takes gas service. The required receipt point is one of the following points defined depending on the interstate gas transportation pipeline used to transport the gas into New England: Algonquin Gas Pipeline – Ramapo; Tennessee Gas Pipeline- receipt points in TGP Zone 5; Iroquois Gas Transmission System – Wright; Portland Natural Gas Transmission System – Iroquois (on TransCanada). No required receipt point is identified for the Maritimes and Northeast Pipeline. Firm gas transportation contracts for service over the Maritimes and Northeast Pipeline cannot be used to bring gas into New England and, if relied on, must be joined with a contract for transportation service over one of the other four interstate gas transportation pipelines that brings the gas into New England.

(z) The "contract path" for the firm gas transportation contract(s) is the path along the pipeline(s) between the contract receipt point and the contract delivery point. Where more than one firm gas transportation contract is utilized to satisfy the requirements of this Section III.15.2.1.6.2.1, the contract receipt point and contract delivery point may be specified in separate contracts, so long as the totality of the contract path meets the requirements specified below.

(ii) *Receipt and Delivery Point Requirements.* The firm gas transportation contract(s) (entered into directly or indirectly) must meet the following two criteria: first, the required receipt point must be within the contract path and, second, the required delivery point must be within the contract path.

III.15.2.1.6.2.2. LNG Supply Firming Requirements

A resource may satisfy the gas firming requirements for the designated Firm Gas Capacity by entering into a contract (one or more) with a liquified natural gas terminal (or its Affiliate) that provides natural

gas to New England via pipeline transportation (Saint John LNG, Everett Marine Terminal, and the Northeast Gateway) that meets the requirements of this Section III.15.2.1.6.2.2.

(a) *Contract Quantity (Duration and Volume).* The liquified natural gas supply contract must provide the resource with gas for a minimum duration of 15 days during the Gas Firming Period with a maximum daily quantity of gas sufficient to permit the resource to generate at the Firm Gas Capacity MW quantity for 16 hours per day. The contract may not place undue limitations on the right to call and receive the volume of gas needed to meet the maximum daily quantity for any hour of the day or for any day of the Gas Firming Period.

(b) *Contract Type*. The liquified natural gas supply contract must be either (1) a take-or-pay contract or (2) a call option contract with a fixed reservation charge and a commodity charge. If the commodity charge for the call option contract is fixed, it must be no more than the greater of 125 percent of the average of Intercontinental Exchange Algonquin Citygates Fixed Price Future (ALG) for December, January, and February as of the date the liquified natural gas supply contract is executed, and $25/MMBtu. If the commodity charge for the call option contract is indexed, it must be no more than 300% of the Platts Gas Daily average price for: Henry Hub; Columbia Gas, App.; Eastern Gas, South; Texas Eastern, M-2 receipts; or Transco, Leidy Line receipts.

III.15.2.1.6.3. Release Rights

A resource satisfying the gas firming requirements for designated Firm Gas Capacity via a contract for liquid natural gas pursuant to Section III.15.2.1.6.2.2 is permitted to sell the contracted gas without limitation. A resource satisfying the gas firming requirements for designated Firm Gas Capacity via firm gas transportation service pursuant to Section III.15.2.1.6.2.1 is permitted to sell any portion of its transportation rights for an Operating Day (1) at any time following the Day-Ahead Market offer submittal deadline for the Operating Day, or (2) if that Firm Gas Capacity is otherwise unavailable (e.g., due to forced outage) for the Operating Day for reasons other than the inability to procure fuel. A resource holding firm gas transportation service shall not be prohibited from releasing that service on a recallable basis so long as the terms of that release do not prevent the resource from complying with the conditions on release set forth herein.

III.15.2.1.6.4. Firm Gas Information Submission Requirements

Market Participants designating some or all of the capacity of a resource as Firm Gas Capacity shall provide the following information to the ISO:

(a) *Contract Information*. The Lead Market Participant for the resource shall provide the ISO with copies of all contracts and arrangements that the Lead Market Participant is relying on to meet the gas firming requirements in this Section III.15.2.1.6 for the designated quantity of Firm Gas Capacity.

(b) *Affidavit*. The Lead Market Participant for the resource shall provide the ISO with an affidavit signed by an officer of the Lead Market Participant's company stating that the contracts and other relevant documentation submitted to the ISO pursuant to this Section III.15.2.1.6.4 satisfy the pipeline gas transportation firming requirements in Section III.15.2.1.6.2.1 or the liquified natural gas supply firming requirements in Section III.15.2.1.6.2.2, as applicable, for the MW quantity of the resource being designated as Firm Gas Capacity.

III.15.2.2. Monthly Reconfiguration Auction Qualification.

For a resource that has not previously obtained a Capacity Supply Obligation in a~~n Annual~~ Seasonal Capacity Auction or Forward Capacity Auction to qualify as a Capacity Resource for the purpose of participation in a Monthly Reconfiguration Auction pursuant to Section III.15.5 or bilateral activities pursuant to Section III.15.6, ~~prior to the Capacity Demonstration Deadline for the relevant month a~~the Lead Market Participant associated with the resource must: (1) submit the Qualification Data Submission Package as described in Section III.15.2.1 (except for the information described at Section III.15.2.1.2) at least ~~by~~ seven Business Days prior to the Capacity Demonstration Deadline for the relevant month, except that an Import Capacity Resource ~~or a Resource seeking ISO-estimated Seasonal Qualified Capacity Values pursuant to Section III.15.2.6(d)~~ must submit its Qualification Data Submission Package at least ~~30~~ 60 calendar days prior to the Capacity Demonstration Deadline for the relevant month; and (2) complete a capacity demonstration prior to the Capacity Demonstration Deadline for the relevant month pursuant to Section III.15.2.6.

III.15.2.3. Deliverability Review.

A Generating Capacity Resource, Active Demand Capacity Resource, Import Capacity Resource associated with an External Elective Transmission Upgrade, and Distributed Energy Capacity Resource must satisfy the deliverability review requirements described in this Section III.15.2.3 in order to qualify capacity for participation in a~~n Annual~~ Seasonal Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction above the deliverability value associated with the resource's qualification for any previous Forward Capacity Auction, ~~Annual~~ Seasonal Capacity Auction, Monthly Reconfiguration Auction, or bilateral transaction. None of the provisions of this Section III.15.2, supersedes, replaces, or

satisfies any of the requirements of Schedules 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder.

III.15.2.3.1. Deliverability Review for Capacity Resources Associated with Generating Facilities or External Elective Transmission Upgrades Subject to Schedule 22, 23, or 25 of Section II of the Tariff.

A Generating Facility or External Elective Transmission Upgrade subject to Schedules 22, 23 or 25 of Section II of the Tariff must complete the applicable interconnection processes set forth therein and have been assigned, as applicable, either Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service, as necessary to support the delivery of the associated Capacity Resource's ~~Qualified Capacity~~ Seasonal MRI Capacity.

III.15.2.3.2. Deliverability Review for Capacity Resources Associated with Resources Not Subject to Schedule 22, 23, or 25 of Section II of the Tariff.

For a Generating Capacity Resource, Active Demand Capacity Resource, or Distributed Energy Capacity Resource not subject to Schedules 22, 23, or 25 of Section II of the Tariff, the ISO shall perform a deliverability review based on: (1) the information provided in the resource's Qualification Data Submission Package; and (2) the results of the ISO's most recent deliverability analysis, performed consistent with the criteria and conditions conducted as described in the ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that such a resource cannot deliver any of the requested incremental capacity, then the resource or incremental portion thereof shall not qualify for participation in the Capacity Market as reflected in the Seasonal ~~Qualified~~ MRI Capacity ~~V~~values issued pursuant to Section III.15.2.9~~7~~; otherwise, the ISO shall determine that the requested Seasonal MRI Capacity ~~Qualified Capacity~~ of the Capacity Resource are~~is~~ deliverable, and the Capacity Resource shall be eligible to continue to proceed with the remainder of the processes described in this Section III.15.2.

III.15.2.4. Resources Previously Counted as Capacity.

Resources that have previously counted as capacity shall, for the purposes of Section III.15.2, be treated as if they had never previously obtained a Capacity Supply Obligation in a~~n Annual~~ Seasonal Capacity Auction or Forward Capacity Auction if: (1) there is a material change to the Capacity Resource as described in III.15.2.4.1, or (2) if a deactivated or retired resource seeks to re-enter the Capacity Market pursuant to III.15.2.4.2.

III.15.2.4.1. Material Change to a Capacity Resource.

(a) A Lead Market Participant that materially changes a Capacity Resource that has previously received a Capacity Supply Obligation in a~~n Annual~~ Seasonal Capacity Auction or Forward Capacity Auction, or plans to do so prior to the relevant Capacity Demonstration Deadline, may, by the relevant Qualification Data Submission Deadline or at least seven Business Days prior to the relevant monthly Capacity Demonstration Deadline, inform the ISO of that material change, update the information provided under Section III.15.2.1.1 to reflect the change to the Capacity Resource, and demonstrate its updated Commercial Capacity pursuant to Section III.15.2.6. If the ISO determines that a material change has occurred and been demonstrated, ~~The~~an updated ~~Qualified Capacity~~Seasonal MRI Capacity of the resource, accounting for the change, shall be calculated in accordance with Section III.15.3.1 for the subsequent ~~Annual~~ Seasonal Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral. The Seasonal ~~Qualified~~ MRI Capacity~~-~~ of a Capacity Resource that notifies the ISO of a material change but does not demonstrate pursuant to III.15.2.6 shall remain unmodified until demonstration of the material change occurs.

(b) For purposes of this Section III.15.2.4, a material change to a Capacity Resource is a change to the design or operating characteristics of the resource, including its interconnection facilities, that may have a significant effect on the reliability or operating characteristics associated with the Capacity Resource, and shall include, but not be limited to, changing the resource technology type, making a change to the Capacity Resource that increases or decreases the resource's ~~Annual Qualified Capacity~~ Seasonal Maximum Capability by greater than the lesser of 5 MW or 10 percent, or any change to the resource that requires a material modification to its interconnection agreement. For any change to a Capacity Resource other than the changes specifically described in this Section III.15.2.4.1(b) that a Lead Market Participant seeks to identify as a material change and submit pursuant to Section III.15.2.4.1(a), ~~No less than 30 calendar days prior to the Qualification Data Submission Deadline or Monthly Capacity Demonstration Deadline, as relevant, a~~ the Lead Market Participant may request, and the ISO shall within 20 calendar days provide, a determination regarding whether a change qualifies as a material change to a Capacity Resource pursuant to this Section III.15.2.4~~ and requires submission of the materials required pursuant to Section III.15.2.1.1~~.

(c) During the period beginning with the Resource Adequacy Assessment Consultation Deadline and ending with the conclusion of the Seasonal Capacity Auction, any change to a Capacity Resource or the information submitted in a Qualification Data Submission Package shall not impact the Relative MRI value or values used in the determination of the Capacity Resource's Seasonal MRI Capacity for that

Seasonal Capacity Auction unless the change has already been accounted for in the submitted Qualification Data Submission Package, or is made pursuant to Section III.15.2.1.4.

III.15.2.4.2. Treatment of Previously Deactivated or Retired Resources.

In order to qualify for participation in the Capacity Market, a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) must: (1) have reached its deactivation date and reduced its Capacity Network Resource Capability pursuant to Section II.48.3; (2) if the resource was compensated for delaying deactivation through a Commission-approved cost-of-service agreement, have refunded to the ISO all costs subject to refund under the claw-back provision set forth in Section II.54.1; and (3) have satisfied the provisions of Section III.15.2, including submission of the Qualification Data Submission Package described in Section III.15.2.1 and completed the capacity interconnection service requirements described in Section III.15.2.3, as if the resource had never previously received a Capacity Supply Obligation in a Forward Capacity Auction or ~~Annual~~ Seasonal Capacity Auction.

III.15.2.5. Calculation of Advisory ~~Qualified~~ MRI Capacity Values.

Following ~~the~~ each Qualification Data Submission Deadline, by a date ~~in the month of February~~ published on the Capacity Auction Calendar, the ISO shall calculate and provide to Lead Market Participants summer and winter Advisory ~~Qualified~~ MRI Capacity ~~V~~values for each resource that has met the data submission requirements in Section III.15.2.1. ~~The Advisory Qualified Capacity Values of any resource that has not previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or is otherwise treated as if it had not done so, shall equal its demonstrated Commercial Capacity determined in accordance with Section III.15.2.6; except that in the event that a resource has not yet demonstrated a portion of its Commercial Capacity, its Advisory Qualified Capacity Values shall equal the sum of its Commercial Capacity and the estimated incremental Seasonal Qualified Capacity Values of the resource as submitted pursuant to Section III.15.2.1. For all other resources, t~~The Advisory ~~Qualified~~ MRI Capacity Values shall ~~equal~~ be calculated based on the Capacity Resource's ~~summer and winter Qualified~~ Seasonal MRI Capacity as ~~calculated~~ determined pursuant to Section III.15.3.

During the period beginning with the ISO's issuance of Advisory ~~Qualified~~ MRI Capacity Values and ending with the conclusion of the ~~Annual~~ Seasonal Capacity Auction, any change to a ~~capacity~~ Capacity ~~resource~~ Resource or the information submitted in a Qualification Data Submission Package shall not

impact the resource's Seasonal ~~Qualified~~ MRI Capacity ~~V~~values for that ~~Annual~~ Seasonal Capacity Auction unless the change has already been accounted for in the submitted Qualification Data Submission Package, or is made pursuant to Section III.15.2.1.4 or Section III.15.2.~~7~~8.

III.15.2.6. Capacity Commercial Operation Demonstration Requirement.

To participate in a~~n Annual~~ Seasonal Capacity Auction, Monthly Reconfiguration Auction~~s~~, or ~~a~~ Capacity Supply Obligation Bilateral transaction, a Capacity Resource must first demonstrate that its capacity is commercially operational by meeting the demonstration requirements in this Section III.15.2.6 by the applicable Capacity Demonstration Deadline. A resource that meets the demonstration requirements of this Section III.15.2.6 shall be deemed to have achieved Capacity Market Commercial Operation.

(a) Demonstration must be completed (i) prior to a Capacity Resource's initial participation in ~~the~~ a ~~Annual~~ Seasonal Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation ~~b~~Bilateral transaction, and (ii) when a Capacity Resource that has previously received a Capacity Supply Obligation ~~in a Forward Capacity Auction or Annual Capacity Auction~~ materially changes or reactivates pursuant to Section III.15.2.4.

(b) The Capacity Demonstration Deadline for each ~~Annual~~ Seasonal Capacity Auction shall be ~~during the month of April preceding the relevant Annual Capacity Auction, as~~ published on the Capacity Auction Calendar and occur during the months described in Section III.15(b); for each Monthly Reconfiguration Auction and Capacity Supply Obligation Bilateral window, the Capacity Demonstration Deadline shall precede the relevant Obligation Month by approximately two weeks, as published on the Capacity Auction Calendar.

(c) The performance demonstration requirements that must be met by the relevant Capacity Demonstration Deadline for a Capacity Resource are as follows:~~To demonstrate commercial capacity, a resource must perform an audit by the relevant Capacity Demonstration Deadline. , using the following audit requirements:~~

~~(i)~~ ~~(i)~~ For a Generating Capacity Resource~~s~~, Active Demand Capacity Resource, Passive Demand Capacity Resource that are composed of Distributed Generation or Load Management, and Distributed Energy Capacity Resources, ~~that are not Intermittent Power~~

~~Resources,~~ each ~~Generator~~ Asset must ~~perform an Establish Claim Capability Audit~~demonstrate performance pursuant to Section III.1.5.~~41.2, provide the data described in ISO New England Operating Procedure No. 23, and have its audit value become effective pursuant to Section III.1.5.1.2(d)(iv).;~~

~~(ii)~~(i)

~~(ii) For Generating Capacity Resources that are Intermittent Power Resources, each Generator Asset must perform a Seasonal Claim Capability Audit pursuant to Section III.1.5.1.3, provide the data described in ISO New England Operating Procedure No. 23, and have its audit value become effective pursuant to Section III.1.5.1.3(i).~~

~~(iii) For Active Demand Capacity Resources, each Demand Response Asset perform a Seasonal DR Audit pursuant to III.1.5.1.3.1, as specified by season in III.15.7.1.5.3(c), requested by the Lead Market Participant, and have its audit value become effective pursuant to Section III.1.5.1.3.1(m).~~

(~~iv~~ii) For Passive Demand Capacity Resources composed of Energy Efficiency~~that are not Active Demand Capacity Resources~~, demonstration is achieved through provision of performance data in the resource's Qualification Data Submission Package in accordance with Section III.15.2.1 and registration of the Energy Efficiency Asset with the ISO; and ~~each Demand Capacity Resource must perform a Passive DR Audit pursuant to III.15.7.1.5.4, as specified by season in III.15.7.1.5.3(c), at the request of the Lead Market Participant, and have its audit value become effective pursuant to Section III.15.7.1.5.4(f).~~

~~(v) For Distributed Energy Capacity Resources, each asset comprising the Distributed Energy Capacity Resource must meet the demonstration requirement in sub-sections (i) through (iii) above for its corresponding asset type.~~

(~~v~~iii~~i~~) For an Import Capacity Resource~~s~~, demonstration is achieved through provision of performance data in the resource's Qualification Data Submission Package in accordance with Section III.15.2.1, except that an Import Capacity Resource~~s~~ associated with an external Elective Transmission Upgrade must demonstrate the ability to transfer power between regions pursuant to Schedule 25, Article 6.

~~(d) For those resources identified in Sections III.15.2.6(c)(ii), III.15.2.6(c)(iv), and III.15.2.6(c)(v) providing asset-level meter-based performance data by the Capacity Demonstration Deadline that is, as determined by the Lead Market Participant, of insufficient duration to establish accurate Seasonal Qualified Capacity Values, or for a period inconsistent with the audit described in Section III.15.2.6(c), the Lead Market Participant may request that the ISO determine Seasonal Qualified Capacity Values based on the lesser of: (1) the Seasonal Qualified Capacity Values requested for qualification by the Lead Market Participant; or (2) the Seasonal Qualified Capacity Values estimated by the ISO. In no instance shall the Seasonal Qualified Capacity Values developed pursuant to this Section III.15.2.6(d) exceed a resource's seasonal Capacity Network Resource Interconnection Service, or its equivalent.~~

~~The ISO-estimated Seasonal Qualified Capacity Values shall be based on technical data requirements for recently commercial resources identified in the Qualification Data Submission Package. The Qualification Data Submission Package of resources seeking ISO-estimated Seasonal Qualified Capacity Values shall include a description of the as-built status of the resource at time of submission, including whether the resource is fully or partially operational. For those resources seeking ISO-estimated Seasonal Qualified Capacity Values, the Qualification Data Submission Package must be submitted to the ISO by the Lead Market Participant by the Qualification Data Submission Deadline for the Annual Capacity Auction, or 30 days prior to the relevant monthly Capacity Demonstration Deadline, with the submission updated at the time of the Capacity Demonstration Deadline to reflect the as-built status of the resource. Resources satisfying the provisions of this Section III.15.2.6(d) shall be deemed to have demonstrated Commercial Capacity.~~

~~Resources seeking ISO-estimated Seasonal Qualified Capacity Values that have completed the relevant audit described in III.15.2.6(c) for only one season may elect to use the ISO-estimated Seasonal Qualified Capacity Values for one or both seasons. The ISO-estimated Seasonal Qualified Capacity Values may constitute a resource's Seasonal Qualified Capacity Value for up to one year after issuance, but shall be valid for no longer than one year after a resource becomes fully operational. A Lead Market Participant may request replacement of ISO-estimated Seasonal Qualified Capacity Values once the relevant seasonal audit has been completed.~~

~~III.15.2.7. Seasonal Qualified Capacity Values and Challenge Process.~~

~~(a) Following the April Capacity Demonstration Deadline, for each Capacity Resource qualified to participate in an Annual Capacity Auction, the ISO shall notify the Lead Market Participant of the~~

~~resource's summer Qualified Capacity and winter Qualified Capacity, calculated in accordance with Section III.15.3, and the Load Zone in which the resource is located. This notification will be provided by the Seasonal Qualified Capacity Notification Date specified in the Capacity Auction Calendar.~~

~~(b) If the Lead Market Participant believes that the ISO has made a mathematical error in calculating the summer Qualified Capacity or winter Qualified Capacity for a Capacity Resource, then the Lead Market Participant must notify the ISO within five calendar days of the Seasonal Qualified Capacity Notification Date.~~

~~(c) If a Capacity Resource's summer Qualified Capacity has been subject to a significant decrease pursuant to Section III.15.3.6, the Lead Market Participant may submit a restoration plan in accordance with Section III.15.3.6(b) within five calendar days of the Seasonal Qualified Capacity Notification Date.~~

~~(d) The ISO shall notify the Lead Market Participant of the outcome of any challenge submitted under (b) above or of its determination regarding the sufficiency of a restoration plan submitted under (c) above, by the date specified in the Capacity Auction Calendar for such responses. In assessing the sufficiency of a restoration plan, the ISO shall determine whether the plan provides sufficient information to support the reasonable likelihood of the resource providing capacity consistent with its summer Qualified Capacity value by the start of the Capacity Commitment Period.~~

~~1. **III.15.2.8. Offers Composed of Separate Resources (Composite Offers).** R~~
~~Separate resources seeking to participate together in an Annual Capacity Auction shall submit a Composite Offer Form no later than the Composite Offer Deadline, which shall be approximately two business days prior to the auction as specified in the Capacity Auction Calendar, with the exception that Distributed Energy Capacity Resources may not participate in composite offers. Composite offers may not be modified or withdrawn after the Composite Offer Deadline. Composite offers must meet the following conditions:~~

~~(a) In all months of the summer period of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources combined meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be a winter month for both the summer resource and the resource combining with that summer resource in that month.~~

~~(b) Each resource that is part of a composite offer must qualify in accordance with all of the provisions of Section III.15.2 applicable to that resource type. A composite offer participates in the Annual Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period.~~

~~(c) The summer Qualified Capacity of a composite offer shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.15.3.7 shall apply, even where one or more of the resources that are part of the offer composed of separate resources is an Intermittent Power Resource. If the winter capacity of the composite offer in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.~~

~~(d) Composite offers are subject to the locational restrictions specified in the following table:~~

		Location of Summer Resource			
		Import-Constrained Capacity Zone	Rest-of-Pool Capacity Zone	Export-Constrained Capacity Zone	Nested Export-Constrained Capacity Zone
Location of Winter Resource	Import-Constrained Capacity Zone	Eligible (within same Capacity Zone)	Eligible	Eligible	Eligible
	Rest-of-Pool Capacity Zone	Ineligible	Eligible	Eligible	Eligible
	Export-Constrained Capacity Zone	Ineligible	Ineligible	Eligible (within same Capacity Zone)	Eligible (within same Capacity Zone where nested export-constrained Capacity Zone is located)
	Nested Export-Constrained Capacity Zone	Ineligible	Ineligible	Ineligible	Eligible (within same Capacity Zone)

III.15.2.~~9~~7. Self-Supplied Capacity.

Where a load serving entity elects to designate all or a portion of its Capacity Load Obligation as self-supplied, the load serving entity must make such designation to the ISO during the self-supply designation window, as published in the Capacity Auction Calendar on the ISO's website. The load serving entity's designation shall specify the MW amount and Lead Market Participant providing the self-supplied capacity. During the ~~Annual~~ Capacity Auction Offer Window, the Lead Market Participant supplying such capacity shall confirm the load serving entity's self-supply designation by specifying each Self-Supplied Capacity Resource and the MW amount of self-supplied capacity in its Capacity Offer. A Generating Capacity Resource or an Import Capacity Resource may be designated as a Self-Supplied Capacity Resource. A Distributed Energy Capacity Resource may only designate its net injection capability as a Self-Supplied Capacity Resource. All self-supplied capacity shall be subject to the eligibility and locational requirements in this Section III.15.2.~~9~~7. If designated as a Self-Supplied Capacity Resource, the resource will clear in the ~~Annual~~ Seasonal Capacity Auction as described in Section III.15.4 and, with the exception of demand programs for Self-Supplied Capacity Resources, shall offset an equal amount of the load serving entity's Capacity Load Obligation in the relevant Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Capacity Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.15.2. All designations as a Self-Supplied Capacity Resource in the ~~Annual~~ Seasonal Capacity Auction qualification process are binding.

III.15.2.~~9~~7.1. Self-Supplied Capacity Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied Capacity Resource, it shall also maintain its status as a Generating Capacity Resource, Import Capacity Resource, or Distributed Energy Capacity Resource and must satisfy the ~~Annual~~ Seasonal Capacity Auction qualification process requirements set forth in the remainder of Section III.15.2 applicable to that resource type, in addition to the requirements of this Section III.15.2.~~9~~7.1. ~~Where a Capacity Offer composed of separate resources is submitted for a Self-Supplied Capacity Resource, all of the requirements and deadlines specified in Section III.15.2.8 shall apply to that offer, in addition to the requirements of this Section III.15.2.9.~~ The total quantity of capacity that a load serving entity designates as self-supplied capacity may not exceed the load serving entity's projected share of the Installed Capacity Requirement, expressed in terms of Seasonal MRI Capacity, during the Capacity Commitment Period, which shall be calculated by determining the load serving entity's most recent percentage share of like-season Coincident Peak Contribution ~~the Installed Capacity Requirement~~ multiplied by the

projected~~-~~ Installed Capacity Requirement, expressed in terms of Seasonal MRI Capacity for the ~~commitment year~~ Capacity Commitment Period. No resource may be designated as a Self-Supplied Capacity Resource for more than the resource's Seasonal MRI Capacity ~~MW than the lesser of that resource's summer Qualified Capacity~~ for the relevant season~~and winter Qualified Capacity~~.

III.15.2.~~9~~7.2. Locational Requirements for Self-Supplied Capacity Resources.

In order to participate in the ~~Annual~~ Seasonal Capacity Auction as a Self-Supplied Capacity Resource for a load in an import-constrained Capacity Zone, the Self-Supplied Capacity Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied Capacity Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the ~~Annual~~ Seasonal Capacity Auction as a Self-Supplied Capacity Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied Capacity Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.15.2.8. Unexpected Full Forced Outage.

The Seasonal MRI Capacity of a Capacity Resource that has experienced an Unexpected Full Forced Outage of the entire Capacity Resource shall be determined pursuant to this Section III.15.2.8.

(a) In the event that a Capacity Resource experiences an Unexpected Full Forced Outage of the entire Capacity Resource that is expected to remain unresolved for the duration of a full Capacity Commitment Period or more, the Lead Market Participant associated with the Capacity Resource may notify the ISO of the Unexpected Full Forced Outage at least two Business Days prior to the opening of the Capacity Auction Offer Window and request that the Capacity Resource's Seasonal MRI Capacity be reduced to zero for the duration of the relevant Capacity Commitment Period.

(b) In support of a request submitted pursuant to Section III.15.2.8(a), the Lead Market Participant associated with the Capacity Resource shall identify the affected Capacity Resource, the expected duration of the outage, and provide supporting documentation describing the outage that the ISO shall review for consistency with Section III.A.13.3 and ISO New England Operating Procedure No. 5. Within two Business Days of such a request, the ISO shall respond indicating whether it accepts the request and identifying the resulting Seasonal MRI Capacity.

(c) A Capacity Resource that has had its Seasonal MRI Capacity reduced to zero pursuant to Section III.15.2.8(b) shall be ineligible to participate in the Seasonal Capacity Auction, Monthly Reconfiguration Auctions, or Capacity Supply Obligation Bilaterals for the relevant Capacity Commitment Period.

III.15.2.~~10~~9. ~~Publication~~ Issuance of Seasonal~~Annual Qualified~~ MRI Capacity Values for the ~~Annual~~ Seasonal Capacity Auction.

The ISO shall provide a Seasonal MRI ~~Annual Qualified~~ Capacity value~~s~~ determined pursuant to Section III.15.3 for the relevant season to Lead Market Participants of each Capacity Resource participating in a~~n~~ ~~Annual~~ Seasonal Capacity Auction no less than one business day before the opening of the ~~Annual~~ Capacity Auction Offer Window set forth in the Capacity Auction Calendar.

For each Import Capacity Resource participating in a Seasonal Capacity Auction, the ISO shall provide the Lead Market Participant a preliminary Seasonal MRI Capacity value at least seven Business Days prior to issuance of the Seasonal MRI Capacity values for the relevant Seasonal Capacity Auction and the Lead Market Participant shall respond confirming acceptance of that value or seeking a lesser value, as further described in Section III.15.3.2(f), at least three Business Days Prior to the issuance of the Seasonal MRI Capacity values for the relevant Seasonal Capacity Auction.

III.15.2.10. Issuance of Monthly MRI Capacity Values for Monthly Reconfiguration Auctions and Capacity Supply Obligation Bilaterals.

The ISO shall provide Monthly MRI Capacity values determined pursuant to Section III.15.3 for the relevant month according to the Monthly Reconfiguration Auction and Capacity Supply Obligation Bilateral timelines described in the Capacity Auction Calendar.

III.15.2.11. Publication of Offer Information.

(a) The number of ~~For each~~ Capacity Offer~~s, the quantity and~~ by Load Zone (or interface, as applicable) ~~in which the resource is located~~ will be published to the ISO's website no later than 15 days after the ~~Annual~~ Seasonal Capacity Auction is conducted.

(b) For Capacity Offers from Import Capacity Resources, the name of submitter, ~~quantity~~number of Capacity Offers, and interface shall be published to the ISO's website no later than 15 days after the ~~Annual~~ Seasonal Capacity Auction is conducted.

(c) The name of each Lead Market Participant submitting Capacity Offers, as well as the number of Capacity Offers submitted by each Lead Market Participant, shall be published to the ISO's website no

later than 15 calendar days after the issuance of Advisory ~~Qualified Capacity~~MRI Capacity Values. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Capacity Offers upon request pursuant to Section 3.3 of the ISO New England Information Policy.

III.15.3. Capacity Resource Accreditation.

Pursuant to the provisions of this Section III.15.3, the ISO shall determine a Seasonal MRI Capacity value and, where applicable, a Monthly MRI Capacity value for each Generating Capacity Resource, Import Capacity Resource, Demand Capacity Resource, and Distributed Energy Capacity Resource.

(a) For purposes of this Section III.15.3, the term MRI Capacity shall refer to either the Seasonal MRI Capacity value or the Monthly MRI Capacity value calculated for use in the Seasonal Capacity Auctions, the Monthly Reconfiguration Auctions, or the monthly trading activities, as applicable. Seasonal MRI Capacity values shall utilize the Maximum Capability values calculated during the Seasonal Capacity Auction qualification process. Monthly MRI Capacity values shall utilize the Maximum Capability values calculated during the Monthly Reconfiguration Auction qualification process.

(b) For the purposes of determining Seasonal MRI Capacity, the Maximum Capability for resources that have previously received a Capacity Supply Obligation in a Forward Capacity Auction or like-season Seasonal Capacity Auction shall not exceed the greater of: (1) the Capacity Resource's highest previous like-season Maximum Capability used to determine Seasonal MRI Capacity, adjusted for deactivations and retirements (or for the Capacity Commitment Periods beginning June 1, 2028 and November 1, 2028, the highest previous like-season Qualified Capacity, adjusted for deactivations and retirements), or (2) the Maximum Capability value submitted pursuant to III.15.2, adjusted for deactivations, unless the resource has qualified and demonstrated the additional capacity pursuant to Section III.15.2.4.1.

III.15.3.1. Resource Technology Types for Capacity Accreditation.

For purposes of determining Relative MRI values and MRI Capacity values, each resource shall be assigned to one of the following technology types in accordance with this Section III.15.3.1.

(a) Generating Capacity Resources other than Intermittent Power Resources.

(i) **Generating Capacity Resources Without Energy Limitations.** A Generating Capacity Resource that is not an Intermittent Power Resource and does not otherwise contain the resource characteristics identified in sub-sections (ii) through (iv), shall be categorized as a Generating Capacity Resource Without Energy Limitations.

(ii) **Energy-Limited Generating Capacity Resources.** A Generating Capacity Resource with the following characteristics shall be categorized as an Energy-Limited Generating Capacity Resource.

(1) An oil-only Generating Capacity Resource with one or more assets that are each capable of operating with fuel oil as their only fuel type, where the resource has a summer or winter Seasonal Qualified Inventory value that does not allow the resource to operate continuously at its Seasonal Maximum Capability for a minimum of 24 hours.

(2) For a Winter Capacity Commitment Period, a dual-fuel Generating Capacity Resource with one or more assets that are capable of switching between operation on natural gas and fuel oil, and has a fuel oil winter Seasonal Qualified Inventory value that does not allow the resource to operate continuously for a minimum of 24 hours at the greater of its Winter Maximum Capability for fuel oil and its Winter Maximum Capability for natural gas.

(iii) **Energy Storage Generating Capacity Resources.** A Generating Capacity Resource with one or more assets each of which satisfy the requirements of Section III.1.10.6, which includes but is not limited to stand-alone battery storage facilities and pumped storage facilities, shall be categorized as an Energy Storage Generating Capacity Resource.

(iv) **Hybrid Generating Capacity Resources.** A Generating Capacity Resource with the following characteristics shall be categorized as a Hybrid Generating Capacity Resource. Hybrid Generating Capacity Resource configurations under paragraphs (1) and (2) below shall each be referred to as a "facility" for purposes of the determination of MRI Capacity and related values.

(1) A Generating Capacity Resource comprising one or more Generator Assets of different technology types that are electrically connected to each other behind a common Point of Interconnection.

(2) A Generating Capacity Resource comprising one or more Generator Assets of different technology types that shares a common Point of Interconnection with and is electrically connected to at least one other Generating Capacity Resource.

(b) Intermittent Power Generating Capacity Resources. A Generating Capacity Resource with one or more assets each of which is an Intermittent Power Resource shall be categorized as an Intermittent Power Generating Capacity Resource.

(c) Demand Capacity Resources. A Demand Capacity Resource shall be either an Active Demand Capacity Resource or a Passive Demand Capacity Resource.

(d) Distributed Energy Capacity Resources.

(e) Import Capacity Resources.

III.15.3.2. MRI Capacity Values.

For each Capacity Resource that qualifies for participation in the Seasonal Capacity Auction pursuant to Section III.15.2 or the Monthly Reconfiguration Auctions pursuant to Section III.15.5, or Capacity Supply Obligation Bilateral pursuant to Section III.15.6, an MRI Capacity value shall be determined in accordance with this Section III.15.3.2.

(a) Generating Capacity Resources other than Intermittent Power Resources.

(i) **Generating Capacity Resources Without Energy Limitations.**

(1) For resources included in the resource adequacy assessment process addressed in Section III.12, the MRI Capacity value shall be the product of the resource's Seasonal Maximum Capability and its Relative MRI determined in accordance with Section III.12.1.2.

(2) For resources not included in the resource adequacy assessment process addressed in Section III.12, the MRI Capacity value shall be the product of the resource's Seasonal Maximum Capability and a representative Relative MRI. The representative Relative MRI shall be determined using the resource's Seasonal Maximum Capability and EFORd values and a regression model developed from the attributes of all Generating Capacity Resources Without Energy Limitations for which a Relative MRI has been calculated pursuant to Section III.12.1.2.

(ii) **Energy-Limited Generating Capacity Resources.**

(1) For oil-only resources included in the resource adequacy assessment process addressed in Section III.12, the MRI Capacity value shall be the product of the resource's Seasonal Maximum Capability and its Relative MRI determined in accordance with Section III.12.1.2, adjusted pursuant to Section III.15.3.3.

(2) For oil-only resources not included in the resource adequacy assessment process addressed in Section III.12, the MRI Capacity value shall be the product of the resource's Seasonal Maximum Capability and a representative Relative MRI, adjusted to account for the resource's EFORd, and further adjusted thereafter pursuant to Section III.15.3.3. The representative Relative MRI shall be determined using a duration curve that expresses a resource's unadjusted Relative MRI as a function of the number of hours that the resource's Daily Maximum Usable Energy will allow it to operate continuously at its Seasonal Maximum Capability.

(3) For dual-fuel resources, the MRI Capacity value shall be determined using the following process. The greater of the resource's oil-based or gas-based Seasonal Maximum Capability shall be used in both of the following calculations.

(x) *Calculation of an oil-only MRI Capacity value*. An MRI Capacity value shall be calculated for the resource using the methodology set forth in sub-section (1) above for oil-only Energy-Limited Generating Capacity Resources.

(y) *Calculation of a gas-only MRI Capacity value*. An MRI Capacity value shall be calculated for the resource using the methodology set forth in sub-section (a)(i)(2) above for Generating Capacity Resources Without Energy Limitations not included in the resource adequacy assessment process.

If the resource's oil-based Seasonal MRI Capacity value is greater than its gas-based MRI Capacity value, then the resource's MRI Capacity value shall be the oil-based MRI Capacity value, and the resource shall be treated as an oil-only resource in the Seasonal Capacity Auction.

If the resource's gas-based MRI Capacity value is greater than its oil-based MRI Capacity value, then the resource's MRI Capacity value shall be the gas-based MRI Capacity value, and the resource shall be treated as a gas-only resource in the Seasonal Capacity Auction. The difference between the gas-based MRI Capacity value and the oil-based MRI Capacity value shall be treated as non-firm gas capacity unless it satisfies the Firm Gas Capacity requirements in Section III.15.2.1.6.

(iii) **Energy Storage Generating Capacity Resources.**

(1) For resources included in the resource adequacy assessment process addressed in Section III.12, the MRI Capacity value shall be the product of the resource's Seasonal Maximum Capability and its Relative MRI determined in accordance with Section III.12.1.2, adjusted pursuant to Section III.15.3.3.

(2) For resources not included in the resource adequacy assessment process addressed in Section III.12, the MRI Capacity value shall be the product of the resource's Seasonal Maximum Capability and a representative Relative MRI, adjusted to account for the resource's EFORd, and further adjusted thereafter pursuant to Section III.15.3.3. The representative Relative MRI shall be determined using a duration curve that expresses a resource's unadjusted Relative MRI as a function of the number of hours that the resource's maximum storage capacity will allow it to operate continuously at its Seasonal Maximum Capability.

(iv) **Hybrid Generating Capacity Resources.**

(1) For resources included in the resource adequacy assessment process addressed in Section III.12, the MRI Capacity value of the resource shall be derived from a facility-level MRI Capacity value calculated as the product of the facility limit (MW) and facility-level Relative MRI determined in accordance with Section III.12.1.2.2(a)(iv). For a facility composed of a single resource, the resource's MRI Capacity value shall equal the facility-level MRI Capacity value. For a facility composed of more than one resource, the resource's MRI Capacity value shall be determined by allocating the facility-level MRI Capacity value to the individual resources using the allocation percentages specified by the Lead Market Participant, subject to a cap equal to the individual resource's Seasonal Maximum Capability.

(2) For resources not included in the resource adequacy assessment process addressed in Section III.12, the MRI Capacity value of the resource shall be derived from a facility-level MRI Capacity Value and a component-level MRI Capacity value. The facility-level MRI Capacity value shall be the sum of the relevant MRI Capacity values of the components of the facility, capped at the facility limit. The component-level MRI Capacity values shall be calculated as the product of the Seasonal Maximum Capability of the component and a representative Relative MRI determined in accordance with the provisions of this Section III.15.3.2 for non-modeled resources of the corresponding technology type.

For a facility composed of a single resource, the resource's MRI Capacity value shall equal the facility-level MRI Capacity value. For a facility composed of more than one resource, the resource's MRI Capacity value shall be determined by allocating the facility-level MRI Capacity value to the individual

resources using the allocation percentages specified by the Lead Market Participant, subject to a cap equal to the individual resource's Seasonal Maximum Capability.

(b) Intermittent Power Generating Capacity Resources.

(i) For resources included in the resource adequacy assessment process addressed in Section III.12, the MRI Capacity value shall be the product of the resource's Global Maximum Capability and its Relative MRI determined in accordance with Section III.12.1.2.

(ii) For resources not included in the resource adequacy assessment process addressed in Section III.12, the MRI Capacity value shall be the product of the resource's Global Maximum Capability and a representative Relative MRI. The representative Relative MRI shall be a weighted class-average value derived from the Relative MRI values of resources included in the resource adequacy assessment process within the same class. Classes shall be designed to aggregate resources based on technology type, geographic location, and other characteristics that result in the aggregated resources exhibiting similar performance attributes.

(c) Active Demand Capacity Resources.

(i) For resources included in the resource adequacy assessment process addressed in Section III.12, the MRI Capacity value shall be the product of the resource's Seasonal Maximum Capability, adjusted for transmission and distribution losses, and its Relative MRI determined in accordance with Section III.12.1.2.

(ii) For resources not included in the resource adequacy assessment process addressed in Section III.12, the MRI Capacity value shall be the product of the resource's Seasonal Maximum Capability, adjusted for transmission and distribution losses, and a representative Relative MRI. The representative Relative MRI shall be the weighted average Relative MRI of Active Demand Capacity Resources included in the resource adequacy assessment process associated with the same Lead Market Participant. If the Lead Market Participant is not associated with any such resources, the representative Relative MRI shall be the fleet-wide weighted average Relative MRI of all Active Demand Capacity Resources included in the resource adequacy assessment process.

(d) Passive Demand Capacity Resources.

(i) For Passive Demand Capacity Resources that consist of Energy Efficiency, the MRI Capacity value shall be the sum of the MRI Capacity values calculated for each sector and end use combination that constitute the Passive Demand Capacity Resource. The MRI Capacity value for each of the resource's sector and end use combinations shall be the product of (1) the portion of the resource's Seasonal Maximum Capability equivalent related to the combination, adjusted for transmission and distribution losses, and (2) the Relative MRI for the hypothetical resource representative of the combination determined pursuant to Section III.12.1.2.3(a).

(ii) For Passive Demand Capacity Resources that consist of Distributed Generation or Load Management, the MRI Capacity value shall be the sum of the MRI Capacity values calculated for each group of assets of the same technology type within the Passive Demand Capacity Resource. The MRI Capacity values for each group of assets shall be calculated as follows:

(1) For a group of assets of the same technology type within the resource that has a combined Seasonal Maximum Capability equal to or greater than 5 MW, the MRI Capacity value for such group shall be the product of (a) the group's combined Seasonal Maximum Capability, adjusted for transmission and distribution losses, and (b) the Relative MRI for the group determined pursuant to Section III.12.1.2.3(b)(ii).

For a group of assets of the same technology type within the resource that has a combined Seasonal Maximum Capability less than 5 MW, the MRI Capacity value for such group shall be the product of (a) the group's combined Seasonal Maximum Capability, adjusted for transmission and distribution losses, and (b) the Relative MRI for the group determined pursuant to Section III.12.1.2.3(b)(iii).

(2)

(e) Distributed Energy Capacity Resources.

(i) For resources included in the resource adequacy assessment process addressed in Section III.12, the MRI Capacity value shall be the product of the resource's Seasonal Maximum Capability, with any Demand Response Resource or Demand Response Distributed Energy Resource Aggregation component adjusted for transmission and distribution losses, and its Relative MRI determined in accordance with Section III.12.1.2.

(ii) For resources not included in the resource adequacy assessment process addressed in Section III.12, the MRI Capacity value shall be the product of its Seasonal Maximum Capability, with any Demand Response Resource or Demand Response Distributed Energy Resource Aggregation component adjusted for transmission and distribution losses, and a representative Relative MRI. The representative Relative MRI shall be a weighted average Relative MRI of Distributed Energy Capacity Resources of the same technology that are included in the resource adequacy assessment process. If an insufficient number of Distributed Energy Capacity Resources of the same technology exists, the Relative MRI may instead be based on the values of comparable Active Demand Capacity Resources.

(f) Import Capacity Resources.

(i) For Import Capacity Resources backed by one or more External Resources, the ISO shall determine a preliminary MRI Capacity value that shall be the lesser of (1) the MRI Capacity value submitted by the Lead Market Participant pursuant to Section III.15.2.1.1.1 or (2) an MRI Capacity value determined using the methodology in Section III.15.3.2(a)(i)(2) for a Generating Capacity Resource Without Energy Limitations that is not included in the resource adequacy assessment process, using the Seasonal Maximum Capability equivalent described in Section III.15.2.1.1.1.1. A Lead Market Participant associated with such a resource must, pursuant to the process described in Section III.15.2.9, confirm acceptance of the preliminary Seasonal MRI Capacity value issued by the ISO, or request a lesser value if it anticipates an inability to supply capacity at the level of the preliminary Seasonal MRI Capacity during the relevant Capacity Commitment Period. If the Lead Market Participant does not confirm acceptance of the preliminary value or request a lesser value, its MRI Capacity shall be zero.

(ii) For Import Capacity Resources backed by an external Control Area, the ISO shall determine a preliminary MRI Capacity value that shall be the lesser of (1) the MRI Capacity value submitted by the Lead Market Participant pursuant to Section III.15.2.1.1.1.2 or (2) an MRI Capacity value determined according to the product of the Seasonal Maximum Capability equivalent and Historical Forecast Performance Factor described in Section III.15.2.1.1.1.2. A Lead Market Participant associated with such a resource must, pursuant to the process described in Section III.15.2.9, confirm acceptance of the preliminary Seasonal MRI Capacity value issued by the ISO and submit an allocation of the preliminary Seasonal MRI Capacity value among the Import Capacity Resources it has qualified pursuant to Section III.15.2.1.1.2, or request a lesser value and allocation if it anticipates an inability to supply capacity at the level of the preliminary Seasonal MRI Capacity during the relevant Capacity Commitment Period. If the

Lead Market Participant does not confirm acceptance of the preliminary value or request a lesser value, its MRI Capacity shall be zero.

III.15.3.3 EL/ES Adjustment to Relative MRI of Energy-Limited Generating Capacity Resources and Energy Storage Generating Capacity Resources.

In the calculation of Seasonal MRI Capacity values of each Energy-Limited Generating Capacity Resource and each Energy Storage Generating Capacity Resource, each resource's Relative MRI shall be adjusted by an adder, *EL/ES Adjustment*, which shall be calculated as follows:

$$\textit{EL/ES Adjustment} = rMRI(unadjusted)\ X\ [\frac{1-\max rMRI(ELES)}{\max\ \ rMRI(ELES)})]$$

Where:

- *rMRI(unadjusted)* represents the resource's unadjusted Relative MRI calculated in accordance with Sections III.12.1.2 and III.15.3.
- *max rMRI(ELES))* represents, for Energy-Limited Generating Capacity Resources, the Relative MRI of a hypothetical Energy-Limited Generating Capacity Resource with a 24-hour Daily Maximum Usable Energy value, and for Energy Storage Generating Capacity Resources, the maximum Relative MRI achievable by a hypothetical Energy Storage Generating Capacity Resource of any possible storage duration.

~~Pursuant to the provisions of this Section III.15.3, the ISO shall determine a summer Qualified Capacity, a winter Qualified Capacity, an Annual Qualified Capacity and, where applicable, a Monthly Qualified Capacity for each Generating Capacity Resource, Import Capacity Resource, Demand Capacity Resource, and Distributed Energy Capacity Resource. A Capacity Resource's Seasonal Qualified Capacity Values shall not exceed its seasonal Capacity Network Resource Interconnection Service or equivalent, or Capacity Network Import Interconnection Service, as applicable. Qualified Capacity for resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall not exceed the resource's highest previously received Capacity Supply Obligation unless the resource has demonstrated and qualified the additional capacity pursuant to Section III.15.2.4.1.~~

~~Qualified Capacity values for resources that have never previously obtained a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall be calculated pursuant to Section~~

~~III.15.3.1. Qualified Capacity for resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or a Forward Capacity Auction shall be calculated pursuant to Sections III.15.3.2 through III.15.3.5.~~

~~**III.15.3.1. Qualified Capacity for Resources Never Previously Counted as Capacity.**~~

~~**III.15.3.1.1. Resources Never Previously Counted as Capacity**.~~
~~The summer and winter Qualified Capacity of a Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, or is otherwise treated as such pursuant to the terms of this Section III.15, shall be determined in accordance with the capacity demonstration requirements set forth in Section III.15.2.6, as specified below.~~

~~To determine the Seasonal Qualified Capacity Values of a Generating Capacity Resource that is not an Intermittent Power Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant to Section III.15.2.6(c)(i), the ISO shall use the Section III.1.5.1.2(c) audit results. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3 and III.15.3.2.4, respectively.~~

~~To determine the Seasonal Qualified Capacity Values of a Generating Capacity Resource that is an Intermittent Power Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant Section III.15.2.6(c)(ii), the ISO shall use the Section III.1.5.1.3 audit results. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3 and Section III.15.3.2.4, respectively.~~

~~To determine the Seasonal Qualified Capacity Values of an Active Demand Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(iii), the ISO shall use the Section III.1.5.1.3.1 audit results. To determine the Seasonal Qualified Capacity Values of a Demand Capacity Resource other than an Active Demand Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(iv), the ISO shall use the Section III.15.7.1.5.4~~

audit results. The annual and Monthly Qualified Capacity of such resources shall be determined pursuant to Sections III.15.3.4.2 and III.15.3.4.3, respectively.

To determine the Seasonal Qualified Capacity Values of a Distributed Energy Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant III.15.2.6(c)(v), the ISO shall use the audit results specified therein for the corresponding asset type. The annual and Monthly Qualified Capacity of such a resource shall be determined pursuant to III.15.3.5.2 and III.15.3.5.3, respectively.

To determine the Seasonal Qualified Capacity Values of an Import Capacity Resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and has demonstrated commercial capacity pursuant Section III.15.2.6(c)(vi), the ISO shall use the performance data results specified therein. The annual and monthly Qualified Capacity of such a resource shall be determined pursuant to III.15.3.3.

To determine the Seasonal Qualified Capacity Values of a resource that has never previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction, and that has elected to demonstrate commercial capacity pursuant Section III.15.2.6(d), the ISO shall use the values developed pursuant to Section III.15.2.6(d). The annual Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.3, Section III.15.3.4.2, or Section III.15.3.5.2, as applicable to the relevant resource type. The Monthly Qualified Capacity of such a resource shall be determined pursuant to Section III.15.3.2.4, III.15.3.4.3, or Section III.15.3.5.3, as applicable to the relevant resource type.

III.15.3.2 Qualified Capacity for Generating Capacity Resources.

The summer, winter, annual, and monthly Qualified Capacity for Generating Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.2.

III.15.3.2.1. Summer Qualified Capacity.

(a) For the purpose of Annual Capacity Auction qualification, the summer Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the Capacity Demonstration Deadline each year, with only positive summer ratings

~~included in the median calculation. Where a Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Generating Capacity Resource shall be equal to the median of all the Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the Capacity Demonstration Deadline of each year, with only positive summer ratings included in the median calculation.~~

~~(b) For the purpose of Annual Capacity Auction qualification, the summer Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the average of the median of the Intermittent Power Resource's net output during Summer Intermittent Reliability Hours for each of the previous five summer periods. If there are fewer than five full summer periods since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation, the summer Qualified Capacity of such resource shall be the average of the median of the Intermittent Power Resource's net output during Summer Intermittent Reliability Hours in each of the previous summer periods, or portion thereof, since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation. The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which there was a system-wide Capacity Scarcity Condition, and for Intermittent Power Resources in an import-constrained Capacity Zone, all summer period hours in which there was a Capacity Scarcity Conditions in that Capacity Zone.~~

~~III.15.3.2.2. Winter Qualified Capacity.~~

~~(a) For the purpose of Annual Capacity Auction qualification, the winter Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the Capacity Demonstration Deadline of each year, with only positive winter ratings included in the median calculation. Where a Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Generating Capacity Resource shall be equal to the median of all the Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the Capacity Demonstration Deadline of each year, with only positive winter ratings included in the median calculation.~~

~~(b) For the purpose of Annual Capacity Auction qualification, the winter Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the average of the median of the Intermittent Power Resource's net output during Winter Intermittent Reliability Hours for each of~~

~~the previous five summer periods. If there are fewer than five full summer periods since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation, the winter Qualified Capacity of such resource shall be the average of the median of the Intermittent Power Resource's net output during Winter Intermittent Reliability Hours in each of the previous winter periods, or portion thereof, since the Intermittent Power Resource achieved Capacity Market Commercial Operation or FCM Commercial Operation. The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which there was a system-wide Capacity Scarcity Condition, and for Intermittent Power Resources in an import-constrained Capacity Zone, all winter period hours in which there was a Capacity Scarcity Conditions in that Capacity Zone.~~

~~**III.15.3.2.3. Annual Qualified Capacity.**~~

~~The Annual Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The Annual Qualified Capacity of a Generating Capacity Resource that is an Intermittent Power Resource shall be the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.~~

~~**III.15.3.2.4. Monthly Qualified Capacity.**~~

~~The Monthly Qualified Capacity of a Generating Capacity Resource shall be the resource's most recent Seasonal Claimed Capability value for the season applicable to the relevant month; for those Generating Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.~~

~~**III.15.3.3. Qualified Capacity for Import Capacity Resources.**~~

~~The summer, winter, annual, and monthly Qualified Capacity of an Import Capacity Resource backed by an External Control Area shall be based on the values and data submitted during the qualification process, subject to ISO review and verification. The summer, winter, annual, and monthly Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be based on the data submitted during the qualification process, subject to ISO review and verification, and calculated based on the summer and winter Qualified Capacity of the resources underlying the Import Capacity Resource, in accordance with Sections III.15.3.2.1 and III.15.3.2.2.~~

~~**III.15.3.4. Qualified Capacity for Demand Capacity Resources.**~~

~~The summer, winter, annual, and monthly Qualified Capacity for Demand Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.4.~~

~~**III.15.3.4.1. Summer and Winter Qualified Capacity.**~~

~~(a) For Demand Capacity Resources composed of Energy Efficiency measures, the summer (or winter, as applicable) Qualified Capacity shall equal the sum of the summer (or winter, as applicable) demand reduction values of the installed Energy Efficiency measures as of the Capacity Demonstration Deadline (excluding any capacity that will retire or deactivate, or whose Measure Life will expire, prior to the start of the applicable season of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses).~~

~~(b) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the summer and winter Qualified Capacity shall equal the median of the resource's Seasonal DR Audit value or Passive DR Audit value from the five most recent years, for the relevant season, increased by average avoided peak transmission and distribution losses. Where a Demand Capacity Resource has fewer than five summer or winter Seasonal Audit Values, as applicable, then the summer (or winter) Qualified Capacity for that Demand Capacity Resource shall be equal to the median of all the resource's previous summer (or winter) Seasonal Audit Values, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation.~~

~~**III.15.3.4.2. Annual Qualified Capacity.**~~

~~The Annual Qualified Capacity of a Demand Capacity Resource shall equal the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.~~

~~**III.15.3.4.3 Monthly Qualified Capacity.**~~

~~The Monthly Qualified Capacity of a Demand Capacity Resource, other than a resource composed of Energy Efficiency measures, shall equal its most recent Seasonal DR Audit value or Passive DR Audit value for the season applicable to the relevant month; for those Demand Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified~~

~~Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.~~

~~The Monthly Qualified Capacity of a Demand Capacity Resource composed of Energy Efficiency measures shall equal the most recently-determined summer or winter demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire, deactivate, or whose Measure Life will expire, prior to the start of the relevant Obligation Month, and increased by average avoided peak transmission and distribution losses).~~

~~III.15.3.5. Qualified Capacity of Distributed Energy Capacity Resources.~~

~~The summer, winter, annual, and monthly Qualified Capacity for Distributed Energy Capacity Resources that have previously received a Capacity Supply Obligation in an Annual Capacity Auction or Forward Capacity Auction shall be determined pursuant to this Section III.15.3.5.~~

~~III.15.3.5.1. Summer and Winter Qualified Capacity.~~

~~The summer (or winter, as applicable) Qualified Capacity of a Distributed Energy Capacity Resource that is not an Intermittent Power Resource shall equal the median of the resource's summer (or winter) Seasonal Audit Value from the five most recent years, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation. Where a Distributed Energy Capacity Resource has fewer than five summer (or winter) Seasonal Audit Values, then the summer (or winter) Qualified Capacity for that Distributed Energy Capacity Resource shall be equal to the median of the resource's previous summer (or winter) Seasonal Audit Values, as of the Capacity Demonstration Deadline of each year, with only positive summer (or winter) values included in the median calculation.~~

~~The summer or winter Qualified Capacity of Distributed Energy Capacity Resources that are Intermittent Power Resources shall be determined in accordance with the rules for Generating Capacity Resources that are Intermittent Power Resources in Section III.15.3.2.~~

~~III.15.3.5.2. Annual Qualified Capacity.~~

~~Annual Qualified Capacity for a Distributed Energy Capacity Resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, unless the Distributed Energy Capacity Resource is an Intermittent Power Resource, in which case the Annual Qualified Capacity shall be equal to the resource's summer Qualified Capacity.~~

III.15.3.5.3. Monthly Qualified Capacity.

The Monthly Qualified Capacity of a Distributed Energy Capacity Resource shall equal the most recent Seasonal DECR Audit for the season applicable to the relevant month; for those Distributed Energy Capacity Resources that elect use of ISO-estimated Seasonal Qualified Capacity Values pursuant to III.15.2.6(d), the Monthly Qualified Capacity shall be the ISO-estimated Seasonal Qualified Capacity Value for the season applicable to the relevant month.

III.15.3.6. Adjustment for Significant Decreases in Capacity.

For a Generating Capacity Resource, Import Capacity Resource backed by an External Resource, Distributed Energy Capacity Resource, or Demand Capacity Resource, if the most recent summer Seasonal Claimed Capability rating, summer season Import Capacity Resource performance data submitted pursuant to Section III.15.2.1.1.1, summer Seasonal DECR Audit Value, summer Seasonal DR Audit Value, or summer Passive DR Audit Value as of the Annual Capacity Auction's Capacity Demonstration Deadline is below the resource's Qualified Capacity by more than the threshold defined in the following formula:

$$Threshold = min[max(10\% \times QC_{Summer}, 2\ MW), 10\ MW]$$

Where,

QC_{Summer} = the resource's summer Qualified Capacity

then the Lead Market Participant must elect one of the two treatments set forth in this Section III.15.3.6 by the close of the Seasonal Qualified Capacity Challenge and Restoration Plan Submission Window. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.15.3.6(b) and fails to meet the associated requirements, then the treatment described in Section III.15.3.6(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Annual Capacity Auction only, to have the resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability rating, summer Seasonal DECR Audit Value, Seasonal DR Audit Value, or Passive DR Audit Value as of the Capacity Demonstration Deadline, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) A Lead Market Participant may elect: (i) to submit a restoration plan describing the measures that will be taken and showing that the Generating Capacity Resource, Import Capacity Resource backed

~~by an External Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section III.15.3.2, Section III.15.3.3, Section III.15.3.4, or Section III.15.3.5 by the start of the relevant Capacity Commitment Period; and (ii) to have the Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section III.15.3.2, Section III.15.3.3, Section III.15.3.4, or Section III.15.3.5 for the Annual Capacity Auction. The ISO shall review submitted restoration plans in accordance with the requirements and timelines set forth in Section III.15.2.7.~~

~~III.15.3.7. Resources Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.~~

~~Where a Generating Capacity Resource (other than an Intermittent Power Resource), Demand Capacity Resource, or Import Capacity Resource has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.15.3, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, in accordance with Section III.15.2.8; or (ii) have its Annual Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.~~

~~Where a Distributed Energy Capacity Resource (other than an Intermittent Power Resource) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.15.3, then that resource must have its Annual Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.~~

III.15.4. Seasonal~~Annual~~ Capacity Auction.

III.15.4.1 Capacity Offers.

Lead Market Participants submitting Capacity Offers in the ~~Annual~~ Seasonal Capacity Auction shall submit Capacity Offers for the Capacity Commitment Period associated with the Seasonal~~Annual~~ Capacity Auction as specified in this Section III.15.4.1.

(a) Each Capacity Offer shall be associated with a Capacity Resource for which a~~n Annual Qualified~~Seasonal MRI Capacity value has been established for the ~~Annual~~ Seasonal Capacity Auction through the ~~Annual~~ Seasonal Capacity Auction qualification process set forth in Sections III.15.2 and III.15.3.

(b) Capacity Offers must be submitted during the ~~Annual~~ Capacity Auction Offer Window, the dates of which will be specified as published in the Capacity Auction Calendar. Capacity Offers are not considered final until the close of the ~~Annual~~ Capacity Auction Offer Window and may be amended or corrected as necessary until such time as the window closes.

(c) If a Lead Market Participant fails to submit a Capacity Offer for a resource subject to the requirements of Section III.A.22.1, the ISO shall enter a Capacity Offer for the resource into the ~~Annual~~ Seasonal Capacity Auction in accordance with Section III.A.22.1(d).

(d) Each Capacity Offer must specify at least one price-quantity pair, which consists of one price, denominated in $/kW-month to an accuracy of at most three digits to the right of the decimal point, and a quantity value, expressed in MW to an accuracy of up to three decimal places. Except as provided in Section III.15.4.1(j), t~~T~~he Capacity Offer may specify up to ten price-quantity pairs, where each such pair represents the total amount of capacity offered from the Capacity Resource at the price specified. If more than one price-quantity pair is submitted, the price-quantity pairs must specify prices and quantity values in such a way that, when the price-quantity pairs are ordered from lowest price to highest price, the quantity value in each price-quantity pair increases with each successive, higher-priced price-quantity pair. The price-quantity pair with the greatest specified price must include the Capacity Resource's total ~~Annual~~ Seasonal ~~Qualified~~ MRI Capacity. If the Capacity Offer consists of both a Firm Gas Capacity Offer Portion and a Non-Firm Gas Capacity Offer Portion, the price-quantity pair with the greatest specified price for each of the Firm Gas Capacity Offer Portion and a Non-Firm Gas Capacity Offer Portion must sum to the Capacity Resource's total Seasonal MRI Capacity. The Capacity Offer must not

contain any offer prices less than $0.00/kW-month or greater than the Capacity Auction Offer Price Cap, unless otherwise allowed pursuant to Section III.A.22.2.3 and subsection (e) of this Section III.15.4.1 or required by Section III.A.21 and subsection (f) of this Section III.15.4.1. The Capacity Offer must not specify a total MW quantity value that exceeds the Capacity Resource's ~~Annual Qualified~~ Seasonal MRI Capacity.

(e) A price-quantity pair in a Capacity Offer must not specify a price above the Capacity Offer Price Threshold, except under the following circumstances:

(i) the Lead Market Participant for the Capacity Resource submitted the price-quantity pair to the Internal Market Monitor as part of a Proposed Capacity Offer, pursuant to Section III.A.22.2.2;

(ii) the Internal Market Monitor determined an Allowable Capacity Offer Price relative to the price-quantity pair pursuant to Section III.A.22.2.3; and

(iii) the specified price in the Capacity Offer does not exceed the price specified in the price-quantity pair reviewed by the Internal Market Monitor.

(f) For capacity included in a Capacity Offer that is subject to a Capacity Offer Floor Price pursuant to Section III.A.21.3, the price specified must not be less than the Capacity Offer Floor Price.

(g) A Capacity Offer may specify a Rationing Minimum Limit up to which the offer may not be rationed and must be accepted or rejected in whole. If the Capacity Offer consists of both a Firm Gas Capacity Offer Portion and a Non-Firm Gas Capacity Offer Portion, the Capacity Offer may specify a Rationing Minimum Limit for each the Firm Gas Capacity Offer Portion and the Non-Firm Gas Capacity Offer Portion, provided that the Rationing Minimum Limit for each portion does not exceed the quantity of the Capacity Offer that is allocated to the applicable portion. Without such indication, offers shall be rationable up to the total MW quantity in the offer that is priced at or below the Capacity Offer Price Threshold, subject to the auction clearing constraint described in Section III.15.4.2.2(d). The lowest priced price-quantity pair in a Capacity Offer, Firm Gas Capacity Offer Portion, or Non-Firm Gas Capacity Offer Portion that specifies a Rationing Minimum Limit must specify a quantity value equal to or greater than the specified Rationing Minimum Limit. Notwithstanding the foregoing, a Capacity Offer for an Import Capacity Resource may only specify a Rationing Minimum Limit pursuant to this

subsection (g) if the Import Capacity Resource is associated with an Elective Transmission Upgrade, as described in Section III.15.2.1.1.1.

(h) If the Capacity Offer specifies any price above the Capacity Offer Price Threshold, the Capacity Offer may elect to have the Above-Threshold Offer PortionSegment be treated as rationable, subject to any Rationing Minimum Limit specified pursuant to subsection (g). Without such an election, the Above-Threshold Offer PortionSegment will be treated as non-rationable and accepted or rejected in whole. Notwithstanding the foregoing, a Capacity Offer for an Import Capacity Resource may only elect rationability for the Above-Threshold Offer PortionSegment pursuant to this subsection (h) if the Import Capacity Resource is associated with an Elective Transmission Upgrade, as described in Section III.15.2.1.1.1.

(i) In order to give effect to a self-supply designation made by a load serving entity pursuant to Section III.15.2.79 for any portion of the Capacity Resource's Annual QualifiedSeasonal MRI Capacity, the Capacity Offer for such resource must (i) identify the load serving entity for which its capacity will serve as self-supplied capacity and the MW quantity of self-supplied capacity and (ii) include a price-quantity pair with an offer price of $0.00/kW-month that includes the amount of such capacity, unless such capacity is subject to a Capacity Offer Floor Price. If the self-supplied capacity is subject to a Capacity Offer Floor Price, then the price specified in the price-quantity pair including the self-supplied capacity must equal the Capacity Offer Floor Price.

(j) A Capacity Offer for a gas-fired Generating Capacity Resource or dual-fFuel Generating Capacity Resource (that is treated as a gas-only resource in the Seasonal Capacity Auction) shall consist of a Firm Gas Capacity Offer Portion, a Non-Firm Gas Capacity Offer Portion, or combination thereof. For a gas-fired Generating Capacity Resource, the total MW quantity of a Capacity Offer that has met the election requirements identified in Section III.15.2.1.6 shall be eligible to offer as a Firm Gas Capacity Offer Portion. For a dual-fuel Generating Capacity Resource that is treated as a gas-only resource in the Seasonal Capacity Auction, the total MW quantity of the resource's oil-based MRI Capacity value, in addition to any MW quantity that has met the election requirements identified in Section III.15.2.1.6, shall be eligible to offer as a Firm Gas Capacity Offer Portion. For a gas-fired Generating Capacity Resource, the total MW quantity of a Capacity Offer gdFthat has not met the election requirements identified in Section III.15.2.1.6 shall be considered a Non-Firm Gas Capacity Offer Portion. For a dual-fuel Generating Capacity Resource that is treated as a gas-only resource in the Seasonal Capacity Auction, the total MW quantity that (i) is greater than the resource's oil-based MRI Capacity value and less than the

resource's gas-based MRI Capacity value and (ii) has not met the election requirements identified in Section III.15.2.1.6 shall be considered a Non-Firm Gas Capacity Offer Portion. A Firm Gas Capacity Offer Portion and a Non-Firm Gas Capacity Offer Portion can each consist of up to ten price-quantity pairs.~~with a contract to export capacity during the Capacity Commitment Period must specify an Export Offer Segment and the interface over which the Export Offer Segment will be exported.~~

(k) A Lead Market Participant for a Capacity Resource that is subject to delayed deactivation pursuant to Sections II.52 and II.53 shall not enter a Capacity Offer for any capacity supplied by the Capacity Resource that is subject to delayed deactivation. The ISO shall enter such Capacity Resource's capacity subject to delayed deactivation into the ~~Annual~~ Seasonal Capacity Auction at a price of $0.00/kW-month.

(l) If a prior multi-year Capacity Supply Obligation and Capacity Clearing Price election for the Capacity Resource had been made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 for a Forward Capacity Auction, and the Capacity Resource has continued that election pursuant to III.15.2.1.3, the Capacity Offer submitted for such Capacity Resource must include a price-quantity pair with an offer price of $0.00/kW-month that includes the total amount of the resource's capacity that cleared subject to such election.

III.15.4.2. Conduct of the ~~Annual~~ Seasonal Capacity Auction.

The ISO shall determine Capacity Supply Obligations and Capacity Clearing Prices for the Capacity Commitment Period by conducting the ~~Annual~~ Seasonal Capacity Auction as described in this Section III.15.4.2.

III.15.4.2.1. Replacement of Specified Prices for Mitigation Purposes.

After the ~~Annual~~ Capacity Auction Offer Window, the ISO shall replace specified prices in submitted Capacity Offers as necessary, pursuant to Section III.A.22.2.4(c). Any such adjusted Capacity Offers shall be inputs for the ~~Annual~~ Seasonal Capacity Auction.

III.15.4.2.2. Clearing of the ~~Annual~~ Seasonal Capacity Auction.

(a) In determining Capacity Supply Obligations and Capacity Clearing Prices, the ISO shall employ an optimization algorithm that is designed to maximize social surplus in order to clear Capacity Offers, capacity entered into the auction by the ISO as described in Section III.15.4.1(k), and any Proxy Capacity Offers against the capacity demand curves calculated in accordance with Section III.15.1.1. In clearing

Capacity Offers, the optimization algorithm shall take into account, as applicable, the inputs and constraints set forth in this Section III.15.4.2.2.

(b) The optimization algorithm shall take into account the following: (i) all price-quantity pairs in Capacity Offers for the ~~Annual~~ Seasonal Capacity Auction submitted pursuant to Section III.15.4.1, subject to any adjustments made pursuant to Section III.15.4.2.1 and the constraint described in subsection (c) of this Section III.15.4.2.1; (ii) any Rationing Minimum Limits and rationability elections specified in Capacity Offers pursuant to Section III.15.4.1(g) and Section III.15.4.1(h), respectively; (iii) capacity from a Capacity Resource subject to delayed deactivation pursuant to Sections II.52 and II.53 at a default price of $0.00/kW-month; (iv) the set of distinct Capacity Zones determined to be modeled in the ~~Annual~~ Seasonal Capacity Auction pursuant to Section III.12.4; (v) the System-Wide Capacity Demand Curve calculated in accordance with Section 15.1.1.1; (vi) any Capacity Zone Demand Curves for import-constrained and export-constrained Capacity Zones, calculated in accordance with Sections 15.1.1.2 and 15.1.1.3, respectively; (vii) the Gas-Constrained Winter Capacity Demand Curve calculated in accordance with Section III.15.1.1.4, as relevant for the Winter Seasonal Capacity Auction; (viii) ~~external interface limits~~Capacity Transfer Limits calculated pursuant to Section III.~~12.10~~15.1.3; and (~~vii~~ix) any Proxy Capacity Offers for the ~~Annual~~ Seasonal Capacity Auction as determined pursuant to Section III.A.24.7, which shall be treated as non-rationable.

(c) The optimization algorithm shall not take into account price-quantity pairs in Capacity Offers that specify a price that exceeds the Capacity Auction Offer Price Cap.

(d) Capacity entered into the Seasonal~~Annual~~ Capacity Auction at a price of $0.00/kW-month shall clear the auction.

(e) A Capacity Offer, Firm Capacity Offer Portion, or Non-Firm Capacity Offer Portion that specifies a Rationing Minimum Limit pursuant to Section III.15.4.1(g) shall not clear at quantities less than the specified Rationing Minimum Limit, and Above-Threshold Offer ~~Segments~~ Portions that are non-rationable pursuant to Section III.15.4.1(h) shall not clear at quantities less than the MW quantity of the segment.

(f) [Reserved.]~~For an Export Offer Segment specified in a Capacity Offer that indicates a Generating Capacity Resource's contract to export capacity over an external interface connected to an import-constrained Capacity Zone from another Capacity Zone, or over an external interface connected to the~~

~~Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone, the ISO shall model the Export Offer Segment as though that quantity of capacity were located in the Capacity Zone where the external interface identified in the Capacity Offer is located and adjust Capacity Zone Demand Curves as necessary to reflect such modeling~~.

(g) In determining the clearing result that accounts for auction inputs and satisfies all applicable constraints, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including clearing results where a Capacity Offer with a specified price below the Capacity Clearing Price does not clear.

(h) Where the clearing of the ~~Annual~~ Seasonal Capacity Auction either system-wide or in a single Capacity Zone results in a tie (that is, where two or more resources offer sufficient capacity at prices that would clear the auction ~~at the same minimum costs~~with the same contribution to social surplus), the following rules shall apply in sequence, as necessary, to determine clearing: (i) if multiple Capacity Offers may be rationed, they will be rationed proportionately; and (ii) the Capacity Offer associated with the Lead Market Participant having the lower market share in the capacity auction shall be cleared.

(i) Subject to the other conditions in this Section III.15.4.2.2, including those specified in Section III.15.4.2.2(o), the Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be the price specified by the System-Wide Capacity Demand Curve for the system-wide capacity entered into the ~~Annual~~ Seasonal Capacity Auction that maximizes social surplus. In no case, however, shall the Capacity Clearing Price for the Rest-of-Pool Capacity Zone be less than the highest price specified in an offer for capacity that clears the auction, excluding any capacity that, due to its specified price, would not have cleared but for the fact that it is located within an import-constrained Capacity Zone that has a cleared quantity of capacity equal to or less than the truncation point for the zone's Capacity Zone Demand Curve.

(j) Subject to the other conditions in this Section III.15.4.2.2, including those specified in Section III.15.4.2.2(p), the Capacity Clearing Price for an import-constrained Capacity Zone shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the import-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and

(2) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone as specified in Section III.15.4.2.2(i); and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the import-constrained Capacity Zone and that clears the auction.

(k) Subject to the other conditions in this Section III.15.4.2.2 including those specified in Section III.15.4.2.2(q), the Capacity Clearing Price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the export-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone as specified in Section III.15.4.2.2(i); and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the export-constrained Capacity Zone and that clears the auction.

(l) Subject to the other conditions in this Section III.15.4.2.2, including those specified in Section III.15.4.2.2(r), the Capacity Clearing Price for an export-constrained Capacity Zone that is a nested export-constrained Capacity Zone, shall be the greater of:

(i) the sum of (1) the price specified by the Capacity Zone Demand Curve for the export-constrained Capacity Zone for the quantity of capacity within the zone that clears the auction and (2) the Capacity Clearing Price for the Capacity Zone in which the nested Capacity Zone is located as specified in Section III.15.4.2.2(k); and

(ii) the highest price specified in a Capacity Offer for capacity that is supplied from a resource in the export-constrained Capacity Zone and that clears the auction.

(m) The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for an import-constrained Capacity Zone shall not exceed the Capacity Auction Offer Price Cap. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

(n) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for an interface between the New England Control Area and an external Control Area shall be equal to:

(i) if the quantity of capacity over the external interface that clears the auction is equal to the external interface limit for such interface, the highest price specified in a Capacity Offer for capacity that is supplied from a resource offering capacity over such external interface and that clears the auction; or

(ii) if the quantity of capacity over the external interface that clears the auction is less than the external interface limit for such interface, the Capacity Clearing Price for the Capacity Zone associated with the external interface.

(o) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for a Non-Firm Gas Capacity Offer Portion in the Rest-of-Pool Capacity Zone shall be the greater of:

(i) the sum of: (1) Capacity Clearing Price specified in Section III.15.4.2.2(i) and (2) the price specified by the Gas-Constrained Winter Capacity Demand Curve for the quantity of all cleared Non-Firm Gas Capacity Offer Portions, calculated in accordance with Section III.15.1.1.4; and

(ii) the highest price specified in a Non-Firm Gas Capacity Offer Portion that clears the auction, excluding any capacity that, due to its specified price, would not have cleared but for the fact that it is located within an import-constrained Capacity Zone that has a cleared quantity of capacity equal to or less than the truncation point for the zone's Capacity Zone Demand Curve.

(p) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for a Non-Firm Gas Capacity Offer Portion in an import-constrained Capacity Zone shall be the greater of:

(i) the sum of (1) the Capacity Clearing Price specified in Section III.15.4.2.2(j) and (2) the price specified by the Gas-Constrained Winter Capacity Demand Curve for the quantity of all cleared Non-Firm Gas Capacity Offer Portions, calculated in accordance with Section III.15.1.1.4; and

(ii) the highest price specified in a Non-Firm Gas Capacity Offer Portion that is supplied from a resource in the import-constrained Capacity Zone and that clears the auction.

Notwithstanding the foregoing, under no circumstances shall the Capacity Clearing Price for a Non-Firm Gas Capacity Offer Portion in an import-constrained Capacity Zone be less than the Capacity Clearing Price for a Non-Firm Gas Capacity Offer Portion in the Rest-of-Pool Capacity Zone.

(q) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for a Non-Firm Gas Capacity Offer Portion in an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone shall be the greater of:

(i) the sum of (1) the Capacity Clearing Price specified in Section III.15.4.2.2(k) and (2) the price specified by the Gas-Constrained Winter Capacity Demand Curve for the quantity of all cleared Non-Firm Gas Capacity Offer Portions, calculated in accordance with Section III.15.1.1.4; and

(ii) the highest price specified in a Non-Firm Gas Capacity Offer Portion that is supplied from a resource in the export-constrained Capacity Zone and that clears the auction.

Notwithstanding the foregoing, under no circumstances shall the Capacity Clearing Price for a Non-Firm Gas Capacity Offer Portion in an export-constrained Capacity Zone exceed the Capacity Clearing Price for a Non-Firm Gas Capacity Offer Portion in the Rest-of-Pool Capacity Zone.

(r) Subject to the other conditions in this Section III.15.4.2.2, the Capacity Clearing Price for a Non-Firm Gas Capacity Offer Portion in an export-constrained Capacity Zone that is a nested export-constrained Capacity Zone shall be the greater of:

(i) the sum of (1) the Capacity Clearing Price specified in Section III.15.4.2.2(l) and (2) the price specified by the Gas-Constrained Winter Capacity Demand Curve for the quantity of all cleared Non-Firm Gas Capacity Offer Portions, calculated in accordance with Section III.15.1.1.4; and

(ii) the highest price specified in a Non-Firm Gas Capacity Offer Portion that is supplied from a resource in the export-constrained Capacity Zone and that clears the auction.

Notwithstanding the foregoing, under no circumstances shall the Capacity Clearing Price for a Non-Firm Gas Capacity Offer Portion in a nested export-constrained Capacity Zone exceed the Capacity Clearing Price for a Non-Firm Gas Capacity Offer Portion in the export-constrained Capacity Zone in which the nested export-constrained Capacity Zone is located.

(s) Notwithstanding the other conditions in this Section III.15.4.2.2, under no circumstance shall the Capacity Clearing Price for a Non-Firm Gas Capacity Offer Portion exceed the Capacity Clearing Price for a Firm Gas Capacity Offer Portion in the same Capacity Zone. The Capacity Clearing Price for a Non-Firm Gas Capacity Offer Portion shall not be less than zero.

III.15.4.2.3. Results of the ~~Annual~~ Seasonal Capacity Auction.

(a) ~~Annual~~ Seasonal Capacity Supply Obligations shall be awarded to Capacity Resources in accordance with the results of the ~~Annual~~ Seasonal Capacity Auction clearing mechanics described in Section III.15.4.2.2. ~~For Intermittent Power Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.15.2) shall be adjusted based on the winter Qualified Capacity as determined pursuant to Section III.15.3.2.2.~~ Additional Capacity Supply Obligations may be awarded in accordance with Section III.15.4.2.4.

(b) The Capacity Clearing Prices in each Capacity Zone modeled in the ~~Annual~~ Seasonal Capacity Auction shall be the clearing prices determined as a result of the ~~Annual~~ Seasonal Capacity Auction clearing mechanics described in Section III.15.4.2.2.

III.15.4.2.4. Additional Clearing of Auction in the Event of Cleared Proxy Offers.

If any Proxy Capacity Offer entered into the ~~Annual~~ Seasonal Capacity Auction clears and receives a Capacity Supply Obligation, the ISO shall conduct an additional run of the auction. This additional run shall use the same methodology described in Section III.15.4.2.2, except that the additional run shall (i) exclude all Proxy Capacity Offers and (ii) enter all other capacity that cleared in the primary run of the ~~Annual~~ Seasonal Capacity Auction at a price of $0.00/kW-month. The additional run of the auction shall not affect the Capacity Clearing Prices of the primary run of the ~~Annual~~ Seasonal Capacity Auction pursuant to Section III.15.4.2.2. Capacity (other than capacity still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receives a Capacity Supply Obligation as a result of the primary run of the Seasonal~~Annual~~ Capacity Auction shall be paid the Capacity Clearing Price in the Capacity Zone associated with the capacity during the

associated Capacity Commitment Period. Where the additional run of the auction procures additional capacity, that additionally procured capacity shall be paid the price resulting from the additional run in the Capacity Zone associated with that additional capacity during the associated Capacity Commitment Period, and such price shall be equal to or greater than the price resulting from the primary run of the ~~Annual~~ Seasonal Capacity Auction in that Capacity Zone.

III.15.4.3. Publication of Seasonal~~Annual~~ Capacity Auction Results.

As soon as practicable after the ~~Annual~~ Seasonal Capacity Auction is complete, the ISO shall publish the results of that ~~Annual~~ Seasonal Capacity Auction publicly on its website, including the set of Capacity Zones modeled in the auction, the Capacity Clearing Prices in each of those Capacity Zones, the Seasonal MRI Capacity of each resource that qualified to participate in the auction, and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. The published information shall identify Proxy Capacity Offers that cleared, if any, in the primary run of the ~~Annual~~ Seasonal Capacity Auction.

III.15.5. Monthly Reconfiguration Auctions.

For each Capacity Commitment Period, the ISO shall conduct Monthly Reconfiguration Auctions as described in this Section III.15.5. Monthly Reconfiguration Auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in the Monthly Reconfiguration Auctions. Each reconfiguration auction shall use a static double auction (respecting the interface limits and capacity requirements modeled as specified in Section III.15.5.1) to clear supply offers (i.e., offers to assume a Capacity Supply Obligation) and demand bids (i.e., bids to shed a Capacity Supply Obligation) for each Capacity Zone included in the reconfiguration auction. Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected. Resources that are able to meet the requirements in other Capacity Zones shall be allowed to clear to meet such requirements, subject to the constraints modeled in the auction.

III.15.5.1. Capacity Zones Included in Monthly Reconfiguration Auctions.

Each Monthly Reconfiguration Auction associated with a Capacity Commitment Period shall include each of, and only, the Capacity Zones and external interfaces modeled in the ~~Annual~~ Seasonal Capacity Auction for that Capacity Commitment Period in accordance with Section III.15.4.2.2.

III.15.5.2. Participation in Monthly Reconfiguration Auctions.

Each supply offer and demand bid in a Monthly Reconfiguration Auction must be associated with a specific resource and must satisfy the requirements of this Section III.15.5.2. All resource types may submit supply offers and demand bids in reconfiguration auctions. In accordance with Section III.A.13.2, supply offers and demand bids submitted for Monthly Reconfiguration Auctions shall not be subject to mitigation by the Internal Market Monitor. ~~Offers composed of separate resources may not participate in reconfiguration auctions.~~ Resources with capacity subject to delayed deactivation pursuant to Sections II.52 and II.53 may not participate in reconfiguration auctions, unless otherwise authorized pursuant to the terms of a cost-of-service agreement of the type described in Section II.54.1. Participation in any reconfiguration auction is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of the offer and bid deadline. The ISO will issue a schedule of the submittal windows for Monthly Reconfiguration Auctions in the Capacity Auction Calendar. The offer and bid deadline for each Monthly Reconfiguration Auction shall be announced by the ISO no later than 10 Business Days prior to that deadline. Upon issuance of the monthly bilateral results for the associated Obligation Month, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that monthly auction, as calculated pursuant to this Section III.15.5.2.

III.15.5.2.1. Supply Offers in Monthly Reconfiguration Auctions.

(a) All supply offers in Monthly Reconfiguration Auctions shall be submitted by the Lead Market Participant, and shall specify the resource, the amount of capacity offered in MW, and the price, denominated in $/kW-month.

(b) A resource may not submit a supply offer for a Monthly Reconfiguration Auction unless a Monthly ~~Qualified~~ MRI Capacity value has been established for the resource for the month associated with the Monthly Reconfiguration Auction pursuant to the qualification processes described in Sections III.15.2 and III.15.3.

(c) The amount of capacity up to which a resource may submit a supply offer in a Monthly Reconfiguration Auction shall be the difference (but in no case less than zero) between (i) the resource's Monthly ~~Qualified~~MRI Capacity for the month associated with the auction, as determined pursuant to Section III.15.3 during the most recent qualification process for the resource; and (ii) the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for that month.

III.15.5.2.2. Demand Bids in Monthly Reconfiguration Auctions.

(a) All demand bids in Monthly Reconfiguration Auctions shall be submitted by the Lead Market Participant and shall specify the amount of capacity bid in MW and the price, denominated in $/kW-month.

(b) To submit a demand bid in a Monthly Reconfiguration Auction, a resource must have a Capacity Supply Obligation for the month associated with that Monthly Reconfiguration Auction.

(c) Where capacity associated with a Self-Supplied Capacity Resource that cleared in the ~~Annual~~ Seasonal Capacity Auction for the Capacity Commitment Period is offered in a Monthly Reconfiguration Auction, a resource acquiring a Capacity Supply Obligation in that Monthly Reconfiguration Auction shall not as a result become a Self-Supplied Capacity Resource.

(d) Each demand bid submitted to the ISO for a Monthly Reconfiguration Auction shall be no greater than the amount of the resource's capacity that is already obligated for the month associated with that Monthly Reconfiguration Auction as of the offer and bid deadline for the auction.

III.15.5.3. Clearing Offers and Bids in Monthly Reconfiguration Auctions.

All supply offers and demand bids are rationable and may be cleared in whole or in part in Monthly Reconfiguration Auctions.

III.15.5.4. Conduct of Monthly Reconfiguration Auctions.

Prior to each month in the Capacity Commitment Period, the ISO shall conduct a Monthly Reconfiguration Auction for whole-month capacity commitments during that month. For each Monthly Reconfiguration Auction, the ISO shall employ an optimization algorithm that is designed to maximize social surplus in order to clear the supply offers against demand bids submitted for the auction. The truncation points for import-constrained Capacity Zones and export-constrained Capacity Zones specified in Section III.15.1.1.2 and Section III.15.1.1.3, the truncation point of the Gas-Constrained Winter Capacity Demand Curve specified in Section III.15.1.1.4, and ~~external interface limits established pursuant to Section III.12~~Capacity Transfer Limits established pursuant to Section III.15.1.3 shall be modeled as constraints in the auction. The System-Wide Capacity Demand Curve is not modeled in Monthly Reconfiguration Auctions.

III.15.5.5. Adjustment to Capacity Supply Obligations.

For each supply offer that clears in a Monthly Reconfiguration Auction, the resource's Capacity Supply Obligation for the month associated with the auction shall be increased by the amount of capacity that clears. For each demand bid that clears in a Monthly Reconfiguration Auction, the resource's Capacity Supply Obligation for the month associated with the auction shall be decreased by the amount of capacity that clears.

III.15.6. Bilateral Capacity Contracts.

Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, and Internal Bilaterals for Capacity in accordance with this Section III.15.6, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation. To the extent necessary for the ISO's review and approval of any of the bilateral contracts described in this Section III.15.6, the ISO shall apply the Capacity Zones, ~~Winter~~ Gas Availability Constraint, and external interfaces modeled as inputs and constraints in the ~~Annual~~ Seasonal Capacity Auction for the applicable Capacity Commitment Period, as described in Section III.15.4.2.2. Resources with capacity subject to delayed deactivation pursuant to Sections II.52 and II.53 may not participate in Capacity Supply Obligation Bilaterals, unless otherwise authorized pursuant to the terms of a cost-of-service agreement of the type described in Section II.54.1.

III.15.6.1. Capacity Supply Obligation Bilaterals.

A Capacity Transferring Resource having a Capacity Supply Obligation and seeking to shed that obligation may enter into a Capacity Supply Obligation Bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part, to a Capacity Acquiring Resource, or portion thereof, for a whole-month period during the Capacity Commitment Period, as described in this Section III.15.6.1.

III.15.6.1.1. Terms of and Participation in Capacity Supply Obligation Bilaterals.

(a) Capacity Supply Obligation Bilaterals are available for monthly periods, and a Capacity Supply Obligation Bilateral must be coterminous with a calendar month.

(b) The qualification of Capacity Acquiring Resources for participation in Capacity Supply Obligation Bilaterals is determined in the same manner as the qualification of resources submitting supply offers for Monthly Reconfiguration Auctions as specified in Section III.15.5.2.1(b). A resource that does not have a Monthly ~~Qualified~~ MRI Capacity value established for the month covered by the Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that month.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the monthly Capacity Supply Obligation of the Capacity Transferring Resource. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the amount of unobligated Monthly ~~Qualified~~ MRI Capacity of the Capacity Acquiring Resource for the month covered by the Capacity Supply Obligation Bilateral. For the purpose of this

subsection (c), unobligated Monthly ~~Qualified~~ MRI Capacity refers to the Monthly ~~Qualified~~ MRI Capacity that was determined pursuant to Section III.15.3 in the most recent qualification process for the resource prior to the submission of the Capacity Supply Obligation Bilateral to the ISO and that is not subject to a Capacity Supply Obligation.

(d) A resource, or a portion thereof, that has been designated as a Self-Supplied Capacity Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied Capacity Resource as a result of the transaction.

(e) Capacity Supply Obligation Bilaterals are allowed between a Capacity Transferring Resource and a Capacity Acquiring Resource that are located within different Capacity Zones and across external interfaces modeled as part of the ~~Annual~~ Seasonal Capacity Auction for the Capacity Commitment Period of the relevant monthly period, subject to the transmission interface limits between Capacity Zones and ~~external interface limits~~Capacity Transfer Limits, as described in Section III.15.6.1.4(b).

(f) Participation in any Capacity Supply Obligation Bilateral is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of submission to the ISO.

III.15.6.1.2. Timing of Submission and Prior Notification to the ISO.

The Lead Market Participant for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Capacity Supply Obligation Bilaterals in the Capacity Auction Calendar. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than the end of the relevant submittal window.

III.15.6.1.3. Contents of Submission to the ISO.

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, denominated in $/kW-

month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of $0.00/kW-month.

III.15.6.1.4. ISO Review.

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral and shall reject the Capacity Supply Obligation Bilateral if any of the submission and participation requirements described in this Section III.15.6.1 are not met. For a Capacity Supply Obligation Bilateral submitted before the relevant submittal window opens, this review shall occur once the submittal window opens. For a Capacity Supply Obligation Bilateral submitted after the submittal window opens, this review shall occur upon submission.

(b) After the close of the submittal window, the ISO shall conduct a review to determine the deliverability of the submitted Capacity Supply Obligation Bilaterals. In its review, the ISO shall model as constraints the truncation points for import-constrained Capacity Zones and export-constrained Capacity Zones specified in Sections III.15.1.1.2 and III.15.1.1.3, the truncation point of the Gas-Constrained Winter Capacity Demand Curve specified in Section III.15.1.1.4, and ~~external interface limits~~Capacity Transfer Limits established pursuant to Section III.15.1.3~~2~~ for the applicable Capacity Commitment Period. The ISO shall reject (i) Capacity Supply Obligation Bilaterals that are not fully deliverable up to their specific MW values without violating transmission transfer limits between Capacity Zones or external transfer limits and (ii) Capacity Supply Obligation Bilaterals that are not fully deliverable up to their specific MW values without violating transfer limits between resources that are subject to the Gas-Constrained Winter Capacity Demand Curve specified in Section III.15.1.1.4 and resources that are not subject to the Gas-Constrained Winter Capacity Demand Curve specified in Section III.15.1.1.4. Transactions will only be accepted or rejected in their entirety. The ISO shall approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected, the Lead Market Participant for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the basis for such rejection.

(c) Each Capacity Supply Obligation Bilateral shall be subject to a financial assurance review by the ISO. If the Capacity Transferring Resource and the Capacity Acquiring Resource are not both in compliance with all applicable provisions of the ISO New England Financial Assurance Policy, including those regarding Capacity Supply Obligation Bilaterals, the ISO shall reject the Capacity Supply Obligation Bilateral.

III.15.6.1.5. Approval.

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource for the month covered by the Capacity Supply Obligation Bilateral shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply Obligation of the Capacity Acquiring Resource for the month covered by the Capacity Supply Obligation Bilateral shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

III.15.6.2. Capacity Load Obligations Bilaterals.

A Capacity Load Obligation Transferring Participant seeking to shed its Capacity Load Obligation may enter into a Capacity Load Obligation Bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone to a Capacity Load Obligation Acquiring Participant seeking to acquire a Capacity Load Obligation, as described in this Section III.15.6.2.

III.15.6.2.1. Terms of and Participation in Capacity Load Obligation Bilaterals.

A Capacity Load Obligation Bilateral must be in whole calendar month increments, may not exceed one year in duration, and must begin and end within the same Capacity Commitment Period. A Capacity Load Obligation Transferring Participant will be permitted to transfer, and a Capacity Load Obligation Acquiring Participant will be permitted to acquire, a Capacity Load Obligation if after entering into a Capacity Load Obligation Bilateral and submitting related information to the ISO within the specified submittal time period, the ISO approves such Capacity Load Obligation Bilateral.

III.15.6.2.2. Timing of Submission to the ISO.

Either the Capacity Load Obligation Transferring Participant or the Capacity Load Obligation Acquiring Participant may submit a Capacity Load Obligation Bilateral to the ISO. All Capacity Load Obligation Bilaterals must be submitted to the ISO in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial daily settlements of payments and charges associated with the ~~Annual~~ Capacity Market for the first month of the term of the Capacity Load Obligation Bilateral, a Capacity Load Obligation Bilateral must be submitted to the ISO no later than 12:00 p.m. on the first Business Day of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

III.15.6.2.3. Contents of Submission to the ISO.

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following: (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

III.15.6.2.4. ISO Review.

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section III.15.6.2 are not met.

III.15.6.2.5. Approval.

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral for the period covered by the bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral for the period covered by the bilateral.

III.15.6.3. Internal Bilateral for Capacity.

An Internal Bilateral for Capacity is a transaction subject to the requirements of Section III.1.4 through which two Market Participants agree to the assignment of payments and charges assessed pursuant to Section III.15.8.6 for a period of between one and 24 months for those months beginning on or after June 1, 2028.

III.15.6.3.1. Submission.

An Internal Bilateral for Capacity submissions must specify: (1) the Market Participants that are parties to the transaction; (2) the applicable monthly period(s); (3) the quantity (MW) to an accuracy of up to three decimal places; (4) Capacity Zone to be used in settling the transaction; and (5) whether the transaction shall use the Capacity Clearing Price specified in Section III.15.4.2.2(i)–(m), the Capacity Clearing Price for Non-Firm Gas Offer Portions specified in Section III.15.4.2.2(o)–(s), or the sum of the Capacity Load Obligation charge rates described in Section III.15.8.5.

III.15.6.3.2. Timing.

To be included in the initial daily settlements of payments and charges associated with the Capacity Market for the first month of the term of the Internal Bilateral for Capacity, an Internal Bilateral for Capacity must be submitted to the ISO and subsequently confirmed by the non-submitting Market Participant no later than 12:00 p.m. on the first Business Day of that month.

III.15.7. Obligations of Capacity Suppliers.

Resources assuming a Capacity Supply Obligation through an ~~Annual~~ Seasonal Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a Monthly Reconfiguration Auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.15.7 for each Capacity Commitment Period.

III.15.7.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through an ~~Annual~~ Seasonal Capacity Auction, Monthly Reconfiguration Auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.15.7.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.15.7.1.1. Generating Capacity Resources with Capacity Supply Obligations.

III.15.7.1.1.1. Energy Market Offer Requirements.

(a) A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market whenever the resource is physically available at a MW amount equal to or greater than the product of (1) the ratio of its Capacity Supply Obligation to its Seasonal MRI Capacity, and (2) the Maximum Capability used to determine its Seasonal MRI Capacity. ~~whenever the resource is physically available~~. If the resource is physically available at a level less than ~~its Capacity Supply Obligation~~that amount, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:

(i) the sum of the Generating Capacity Resource's Notification Time plus Start-Up Time plus Minimum Run Time plus Minimum Down Time is less than or equal to 72 hours; or

(ii) if the Generating Capacity Resource cannot meet the offer requirements in Section III.15.7.1.1.1(a)(i) due to physical design limits, then the resource shall be offered into the Day-Ahead Energy Market at a MW amount equal to or greater than its Economic Minimum Limit at a price of zero or shall be self-scheduled in the Day-Ahead Energy Market at a MW amount equal to or greater than the resource's Economic Minimum Limit.

(b) Notwithstanding the foregoing, if the Generating Capacity Resource is a Settlement Only Resource, it may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.1.1.2. Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the known capability of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.19.

III.15.7.1.1.3. [Reserved.]

III.15.7.1.1.4. [Reserved.]

III.15.7.1.1.5. Additional Requirements for Generating Capacity Resources.

Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1 and the requirement to provide to the ISO, upon request and as soon as practicable, confirmation of gas volume schedules sufficient to deliver the energy scheduled for each Generating Capacity Resource using natural gas; and

(c) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures (except that Settlement Only Resources are not subject to outage requirements), provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-

scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.15.7.1.2. Import Capacity Resources with Capacity Supply Obligations.

III.15.7.1.2.1. Energy Market Offer Requirements.

A Market Participant with an Import Capacity Resource must offer one or more External Transactions to import energy in the Day-Ahead Energy Market and Real-Time Energy Market for every hour of each Operating Day at the same external interface that, in total, equal the product of (1) the ratio of the resource's Capacity Supply Obligation to its Seasonal MRI Capacity, and (2) the Maximum Capability used to determine its Seasonal MRI Capacity, except that:

(a) the offer requirement does not apply to any hour in which any External Resource associated with an Import Capacity Resource is on an outage;
(b) the Day-Ahead Energy Market offer requirement does not apply to any hour in which the ~~import transfer capability~~Capacity Transfer Limit of the external interface is 0 MW, and;
(c) the Real-Time Energy Market offer requirement does not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which Coordinated Transaction Scheduling is implemented.

Each External Transaction submitted in the Day-Ahead Energy Market must reference the associated Import Capacity Resource.

Each External Transaction submitted in the Real-Time Energy Market in accordance with Section III.1.10.7 must reference the associated Import Capacity Resource.

III.15.7.1.2.2. Additional Requirements for Import Capacity Resources.

A Market Participant with an Import Capacity Resource that is associated with an External Resource must:

(a) comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the External Resource's native Control Area, and;

(b) notify the ISO of all outages impacting the Capacity Supply Obligation of the Import Capacity Resource in accordance with the outage notification requirements in ISO New England Operating Procedure No. 5.

III.15.7.1.3. Intermittent Power Resources with Capacity Supply Obligations.

III.15.7.1.3.1. Energy Market Offer Requirements.

(a) Market Participants with Intermittent Power Resources that are Dispatchable Resources and have a Capacity Supply Obligation are required to submit offers in the Day-Ahead Energy Market and Real-Time Energy Market whenever the resource is physically available at a MW amount equal to or greater than the product of (1) the ratio of its Capacity Supply Obligation to its Seasonal MRI Capacity, and (2) the Maximum Capability used to determine its Seasonal MRI Capacity.~~consistent with the Market Participant's expectation of the output of the resource in Real-Time~~. If the resource is expected to be physically available at a level less than that amount, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Market Participants with non-dispatchable Intermittent Power Resources with a Capacity Supply Obligation may submit, but are not required to submit, offers into the Day-Ahead Energy Market~~. Market Participants~~ and are required to submit offers for Intermittent Power Resources with a Capacity Supply Obligation for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day-Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

(b) Notwithstanding the foregoing, an Intermittent Power Resource that is a Settlement Only Resource may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.1.3.2. [Reserved.]

III.15.7.1.3.3. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources with Capacity Supply Obligations are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals (except that Intermittent Power Resources that are Settlement Only Resources need not comply with outage requirements).

III.15.7.1.4. [Reserved.]

III.15.7.1.5. Demand Capacity Resources with Capacity Supply Obligations.

III.15.7.1.5.1. Energy Market Offer Requirements.

(a) A Market Participant with an Active Demand Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers for its Demand Response Resources into the Day-Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.15.7.1.5.1; for purposes of the following comparisons, the portion of Demand Reduction Offers not associated with Net Supply shall be increased by average avoided peak transmission and distribution losses. Whenever the Demand Response Resources associated with the Active Demand Capacity Resource are physically available ~~T~~the sum of the Demand Reduction Offers must be equal to or greater than the product of (1) the ratio of the Active Demand Capacity Resource's Capacity Supply Obligation to its Seasonal MRI Capacity, and (2) the Maximum Capability used to determine its Seasonal MRI Capacity. ~~whenever the Demand Response Resources are physically available~~. If the Demand Response Resources are physically available at a level less than the Active Demand Capacity Resource's Capacity Supply Obligation, the sum of the Demand Reduction Offers will equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each Demand Reduction Offer from a Demand Response Resource made into the Day-Ahead Energy Market shall also meet the following requirement:

(i) the sum of the Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time plus Minimum Reduction Time plus Minimum Time Between Reductions is less than or equal to 72 hours.

(b) ~~Seasonal Peak Demand Capacity Resources and On-Peak~~ Passive Demand Capacity Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.1.5.2. Requirement that Offers Reflect Accurate Demand Response Resource Operating Characteristics.

For each day, Demand Reduction Offers submitted into the Day-Ahead Energy Market and Real-Time Energy Market for a Demand Response Resource associated with an Active Demand Capacity Resource must reflect the then-known operating characteristics of the resource. Consistent with Section III.1.10.9(d), Demand Response Resources must re-declare to the ISO any changes to offer parameters that occur in real time to reflect the operating characteristics of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.19.

III.15.7.1.5.3. Additional Requirements for Demand Capacity Resources.

(a) [Reserved.]~~A Market Participant may not associate an Asset with a non-commercial Demand Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Demand Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period~~

(b) [Reserved.]~~An Energy Efficiency measure may be added to an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource (other than one consisting of Load Management or Distributed Generation) until two years after the start of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation; provided, however, that a resource that qualified for a Forward Capacity Auction associated with a Capacity Commitment Period beginning on or before June 1, 2024 may install Energy Efficiency measures until May 31, 2027. Once an Energy Efficiency measure has been associated with an On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource, the measure may not be transferred to a different resource~~.

(c) [Reserved.]~~For purposes of confirming Capacity Market Commercial Operation as described in Section III.15.2.6, the ISO shall use a summer Seasonal DR Audit value or summer Passive DR Audit value to verify the capacity rating of a Demand Capacity Resource with summer Qualified Capacity. A winter Seasonal DR Audit value or winter Passive DR Audit value may only be used to verify the winter commercial capacity of a Demand Capacity Resource. The summer and winter commercial capacity of a Demand Capacity Resource consisting of Energy Efficiency measures may be verified in any month of the year~~

(d) ~~For Active Demand Capacity Resources, a summer Seasonal DR Audit value shall be established for use from April 1 through November 30 and a winter Seasonal DR Audit value shall be established for use from December 1 through March 31. The summer or winter Seasonal DR Audit value of an Active Demand Capacity Resource is equal to the sum of the like-season Seasonal DR Audit values of its constituent Demand Response Resources as determined pursuant to Section III.1.5.1.3.1~~The Seasonal ~~DR Audit~~Maximum Capability value of an Active Demand Capacity Resource shall automatically update whenever a new Seasonal ~~DR Audit~~Maximum Capability value is approved for a constituent Demand Response Resource or with changes to the makeup of the constituent Demand Response Resources.

(e) ~~On-Peak Demand Capacity Resources and Seasonal Peak~~ Passive Demand Capacity Resources shall in addition: (i) comply with the ISO's measurement and verification requirements pursuant to Section III.15.2.1.1.2.1~~.~~ and the ISO New England Manuals; and (ii) comply with the auditing and rating requirements as detailed in Section~~s III.15.7.1.5.4 and~~ III.15.7.1.5.5 and the ISO New England Manuals.

(f) Active Demand Capacity Resources shall in addition: (i) comply with the measurement and verification requirements and the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures; and (ii) comply with the auditing and rating requirements as detailed in Section III.15.7.1.5.5 and the ISO New England Manuals.

III.15.7.1.5.4. On-Peak Demand Capacity Resource and Seasonal Peak Demand Capacity Resource Auditing Requirements.

Passive DR Audits shall no longer occur after August 31, 2027.

~~(d) A summer Passive DR Audit value and a winter Passive DR Audit value must be established for each On-Peak Demand Capacity Resource and Seasonal Peak Demand Capacity Resource in every Capacity Commitment Period during which the On-Peak Demand Capacity Resource or Seasonal Peak Demand Capacity Resource has an annual or monthly Capacity Supply Obligation.~~

~~(e) Summer Passive DR Audit values shall be determined based on data for one or more months of the summer Passive DR Auditing Period (June through August). Winter Passive DR Audit values shall be~~

~~determined based on data for one or more months of the winter Passive DR Auditing Period (December through January).~~

~~(f) Passive DR Audit values shall be made available to the Market Participant within 20 Business Days following the end of the period for which the audit value is determined by the ISO.~~

~~(g) The audit value of an On-Peak Demand Capacity Resource shall be determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the On-Peak Demand Capacity Resource during the Demand Resource On-Peak Hours.~~

~~(h) The audit value of a Seasonal Peak Demand Capacity Resource shall be determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the Seasonal Peak Demand Capacity Resource during the Demand Resource Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in a month during the Passive DR Auditing Period, performance during Demand Resource On-Peak Hours in that month may be used.~~

~~(i) Passive DR Audit values shall become effective one calendar day after being made available to the Market Participant and remain valid until the earlier of: (i) the next like-season Passive DR Audit value becomes effective or (ii) the end of the following Capability Demonstration Year.~~

~~(j) For On-Peak Demand Capacity Resources consisting of Energy Efficiency measures and Seasonal Peak Demand Capacity Resources consisting of Energy Efficiency measures, the ISO shall calculate a summer Passive DR Audit value and a winter Passive DR Audit value in each month of the year. For all other On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources, a Market Participant may request that a summer or winter Passive DR Audit value be determined based on data for, respectively, a summer or winter month outside of the Passive DR Auditing Periods. Such an audit shall not satisfy the Passive DR Audit requirement.~~

III.15.7.1.5.5. Additional Demand Capacity Resource Audits.

The ISO may perform one or both of the following additional audits for a Demand Capacity Resource to establish or verify the capability of the Demand Capacity Resource and its underlying assets and measures.

(a) Level 1 Audit: the ISO shall establish the audit results by conducting a review of records of the Assets and measures to verify that the reported Assets and measures have been installed and are operational. The audit shall include, but is not limited to, reviewing project or program databases, invoices, installation reports, work orders, and field inspection reports. In addition, the audit may involve reviewing any independent inspections or evaluations conducted as part of program implementation and program evaluation.

(b) Level 2 Audit: the ISO shall establish the audit results by initiating or conducting an on-site field audit to verify the installation and performance of the Assets and measures. Such an audit may include a random or select sample of facilities and measures.

A level 1 audit is not required to precede a level 2 audit. If the results of the audit indicate that the demand reduction capability of the Demand Capacity Resource is less than or greater than its most recent like-season ~~Passive DR Audit value or~~ Seasonal ~~DR~~ Maximum Capability~~Audit~~ value or equivalent, then the Demand Capacity Resource's ~~audit value~~ Maximum Capability value or equivalent shall be adjusted accordingly.

III.15.7.1.6. DNE Dispatchable Generator.

III.15.7.1.6.1. Energy Market Offer Requirements.

DNE Dispatchable Generators with a Capacity Supply Obligation must submit offers into the Day-Ahead Energy Market and Real-Time Energy Market whenever the resource is physically available at a MW amount equal to or greater than the product of (1) the ratio of its Capacity Supply Obligation to its Seasonal MRI Capacity, and (2) the Maximum Capability used to determine its Seasonal MRI Capacity. ~~for the full amount of the resource's expected hourly physical capability as determined by the Market Participant~~. If the resource is expected to be physically available at a level less than that amount, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. ~~Market Participants with DNE Dispatchable Generators having a Capacity Supply Obligation must submit offers for the Real-Time Energy Market consistent with the characteristics of the resource~~. For purposes of calculating Real-Time NCPC Charges, DNE Dispatchable Generators shall have a generation deviation of zero.

III.15.7.1.7. Distributed Energy Capacity Resources with Capacity Supply Obligations.

III.15.7.1.7.1. Energy Market Offer Requirements.

(a) A Market Participant with a Distributed Energy Capacity Resource having a Capacity Supply Obligation shall submit offers for its Distributed Energy Resource Aggregations into the Day-Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.15.7.1.7.1; for purposes of the following comparisons, the portion of any Demand Reductions Offers not associated with Net Supply shall be increased by average avoided peak transmission and distribution losses. The sum of the offers whenever the Distributed Energy Resource Aggregations are physically available must be equal to or greater than the product of (1) the ratio of the Distributed Energy Capacity Resource's Capacity Supply Obligation to its Seasonal MRI Capacity, and (2) the Maximum Capability used to determine its Seasonal MRI Capacity.~~whenever the Distributed Energy Resource Aggregations are physically available~~. If the Distributed Energy Resource Aggregations are physically available at a level less than the Distributed Energy Capacity Resource's Capacity Supply Obligation, the sum of the offers must equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each offer from a Distributed Energy Resource Aggregation made into the Day- Ahead Energy Market shall also meet the following requirement:

(i) the sum of the resource's notification time plus start-up time plus Minimum Run Time (or Minimum Reduction Time) plus Minimum Down Time (or Minimum Time Between Reductions) is less than or equal to 72 hours.

(b) Notwithstanding the foregoing, if the Distributed Energy Capacity Resource comprises Settlement Only Distributed Energy Resource Aggregations, it is not obligated to submit Supply Offers into the Day-Ahead Energy Market and may not submit Supply Offers into the Real-Time Energy Market.

III.15.7.1.7.2. Requirement that Offers Reflect Accurate Distributed Energy Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the then-known capability of the resource.

III.15.7.1.7.3. Additional Requirements for Distributed Energy Capacity Resources.

Distributed Energy Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) [Reserved.]~~A Market Participant may not associate an Asset with a non-commercial Distributed Energy Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Distributed Energy Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.~~

(b) Distributed Energy Capacity Resources shall comply with the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

(c) Distributed Energy Capacity Resources shall comply with the auditing and rating requirements as detailed in this Market Rule 1 and the ISO New England Manuals.

(d) For Distributed Energy Capacity Resources, the Seasonal DECR Audit Value shall be established pursuant to Section III.1.7.13.

III.15.7.2. Resources without a Capacity Supply Obligation.

A resource that does not have any Capacity Supply Obligation shall comply with the requirements in this Section III.15.7.2 and shall not be subject to the requirements set forth in Section III.15.7.1 during the Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.15.7.2.1. Generating Capacity Resources without a Capacity Supply Obligation.

III.15.7.2.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. A Generating Capacity Resource that is a

Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.2.1.1.1. Day-Ahead Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Day-Ahead Energy Market. If any portion of the offered energy clears in the Day-Ahead Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the operating day, including the obligation to follow ISO Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.1.1.2. Real-Time Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Real-Time Energy Market. If any portion of the offered energy clears in the Real-Time Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Real-Time Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow ISO Dispatch Instructions. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.1.2. Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation.

Generating Capacity Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with the auditing and rating requirements as detailed in the ISO New England Manuals;

(b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Generating Capacity Resources having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, are not subject to

the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.15.7.2.2. Distributed Energy Capacity Resources without a Capacity Supply Obligation.

III.15.7.2.2.1. Energy Market Offer Requirements.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation is not required to submit offers for the resource into the Day-Ahead Energy Market or Real-Time Energy Market. A Market Participant with a Settlement Only Distributed Energy Resource Aggregation is not permitted to submit an offer for that resource into the Real-Time Energy Market.

III.15.7.2.2.2. Day-Ahead Energy Market Participation.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation may submit an offer into the Day- Ahead Energy Market. If any portion of the offer clears in the Day-Ahead Energy Market, the entire offer, up to the maximum capability offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market so long as it is not a Settlement Only Distributed Energy Resource Aggregation.

III.15.7.2.2.3. Real-Time Energy Market Participation.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation, that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit an offer in the Real-Time Energy Market so long as the resource is not a Settlement Only Distributed Energy Resource Aggregation, and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.2.4. Additional Requirements for Distributed Energy Capacity Resources Having No Capacity Supply Obligation.

Distributed Energy Capacity Resources without a Capacity Supply Obligation shall comply with the requirements in Section III.15.7.1.7.3.

III.15.7.2.3. Intermittent Power Resources without a Capacity Supply Obligation.

III.15.7.2.3.1. Energy Market Offer Requirements.

An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. An Intermittent Power Resource that is a Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.2.3.2. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals; and

(b) Operating Data collection requirements as detailed in the ISO New England Manuals.

III.15.7.2.4. [Reserved.]

III.15.7.2.5. Demand Capacity Resources without a Capacity Supply Obligation.

III.15.7.2.5.1. Energy Market Offer Requirements.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation is not required to offer Demand Reduction Offers for the Demand Response Resource into the Day-Ahead Energy Market or Real-Time Energy Market.

Seasonal Peak Demand Capacity Resources and On-Peak Demand Capacity Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.15.7.2.5.1.1. Day-Ahead Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation may submit a Demand Reduction Offer into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer, up to the Maximum Reduction offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the

Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.5.1.2. Real-Time Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit a Demand Reduction Offer in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.15.7.2.5.2. Additional Requirements for Demand Capacity Resources Having No Capacity Supply Obligation.

Demand Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with Section III.15.7.1.5.3~~(a) and~~ (b) and with the auditing and rating requirements described in Section III.1.5~~5.7.1.5.5~~ and the ISO New England Manuals;

(b) for Active Demand Capacity Resources, complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) for Active Demand Capacity Resources, complying with outage requirements as detailed in the ISO New England Operating Procedures and ISO New England Manuals. Active Demand Capacity Resources having no Capacity Supply Obligation, or that a Lead Market Participant indicates will not have a Capacity Supply Obligation, are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.15.7.3. Exporting Resources.

A resource that is exporting capacity not subject to a Capacity Supply Obligation to an external Control Area shall comply with this Section III.15.7.3 and the ISO New England Manuals. Intermittent Power Resources and Demand Capacity Resources are not permitted to back a capacity export to an external Control Area. The portion of a resource without a Capacity Supply Obligation that will be used in Real-Time to support an External Transaction sale must comply with the energy market offer requirements of Section III.1.10.7 and Section III.1.10.7.A, as applicable.

III.15.7.4. ISO Requests for Energy.

The ISO may request that an Active Demand Capacity Resource, a Generating Capacity Resource, or a Distributed Energy Capacity Resource having capacity that is not subject to a Capacity Supply Obligation provide energy for reliability purposes in the Real-Time Energy Market, but such resource shall not be obligated under this Section III.15 by such a request to provide energy from that capacity. If such resource does provide energy from that capacity, the resource shall be paid based on its most recent offer and is eligible for NCPC.

III.15.7.4.1. Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.15.7.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.

III.15.8. Capacity Payments and Charges.

Revenue in the ~~Annual~~ Seasonal Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.15.8.1 and Capacity Performance Payments as described in Section III.15.8.2, adjusted as described in Section III.15.8.3 and Section III.15.8.4. Market Participants with a Capacity Load Obligation shall be subject to charges as described in Section III.15.8.5. Market Participants engaging in an Internal Bilateral for Capacity shall be subject to the payments and charges described in Section III.15.8.6.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.15 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.15.8.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.15.8.1.1.

III.15.8.1.1. Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (~~i~~a) cleared in a~~n~~ Seasonal~~Annual~~ Capacity Auction, except for the portion of resources designated as Self-Supplied Capacity Resources; (~~ii~~b) cleared in a reconfiguration auction; or (~~iii~~c) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.15.8.1.1 (a) through (~~d~~c) below will be divided by the number of days in the month to derive a ~~d~~Daily Capacity Market ~~s~~Settlement value.

(a) **~~Annual~~ Seasonal Capacity Auction**. For a resource whose offer has cleared in a~~n~~ Seasonal~~Annual~~ Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located, ~~as~~ adjusted as necessary, in the manner described below. ~~by the applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that elected to have the Capacity Clearing Price and the Capacity Supply~~

~~Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer cleared, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only, and subject to the limitations set forth in Section III.15.2.1.3.~~

(i) For those gas-fired Generating Capacity Resources that have a cleared Non-Firm Gas Capacity Offer Portion and did not elect to have the Capacity Clearing Price apply for more than one Capacity Commitment Period pursuant to III.13.1.1.2.2.4 (or that have elected to terminate such treatment pursuant to III.15.2.1.3), the monthly capacity payment shall be adjusted by the applicable Capacity Clearing Price for the cleared Non-firm Gas Capacity Offer Portion pursuant to Section III.15.4.2.2(o)–(s).

(ii) For a resource that elected pursuant to III.13.1.1.2.2.4 to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period and continued such treatment pursuant to III.15.2.1.3, monthly capacity payments associated with the elected Capacity Supply Obligation and Capacity Clearing Price shall continue to apply to the cleared MW quantity associated with the initial election, excluding any obligations procured in the Forward Capacity Auction that were terminated pursuant to Section III.13.3.4A or Section III.15.A.2.1, or withdrawn pursuant to Section III.15.A.2.3, multiplied by the Relative MRI of the resource, for the balance of the elected period, subject to the limitations set forth in Section III.15.2.1.3 and in no case beyond May 31, 2031. The Capacity Clearing Price associated with the election shall be indexed using the most recently published Handy Whitman Index of Public Utility Construction Costs as of a month prior to the start of the Capacity Commitment Period. In addition, the Capacity Clearing Price associated with the initial election shall be divided by the Relative MRI of the resource to determine the monthly capacity payment of Seasonal MRI Capacity denominated Capacity Supply Obligation.

(b) **Monthly Reconfiguration Auctions**. For a resource whose offer or bid has cleared in a Monthly Reconfiguration Auction, the monthly capacity payment or charge shall be equal to the product of its

cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and the price associated with the Capacity Supply Obligation Bilateral.

~~**III.15.8.1.2 Export Capacity**~~

~~If there are any unobligated Export Offer Segments from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the a Annual Seasonal Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows.~~

~~Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ – Capacity Clearing Price $_{\text{location of the resource}}$] x [Cleared MWs of Export Offer Segment]~~

~~Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located = [Capacity Clearing Price $_{\text{location of the interface}}$ – Capacity Clearing Price $_{\text{location of the resource}}$] x [Cleared MWs of Export Offer Segment]~~

~~Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.15.8.5.2.~~

III.15.8.2. Capacity Performance Payments.

III.15.8.2.1. Definition of Capacity Scarcity Condition.

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

III.15.8.2.2. ~~———~~Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.15.8.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) A~~n On-Peak Demand Capacity Resource or Seasonal Peak~~ Passive Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency ~~measures~~Assets, the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation ~~measures~~ Assets submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management Assets~~measures~~ submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.15.8.2.2(c), for any ~~On-Peak Demand Capacity Resource or Seasonal Peak~~Passive Demand Capacity Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.15.8.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(i) A Demand Response Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource's Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource's Actual Capacity Provided shall not be less than zero.

(ii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand

Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

(e) A Distributed Energy Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Metered Quantity for Settlement and Reserve Quantity for Settlement of all the components of its constituent Distributed Energy Resource Aggregations; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Based on the Real-Time operational coordination, the resource must follow any distribution system limitation and update its physical parameters accordingly. The Actual Capacity Provided cannot be less than zero.

(i) The Real-Time demand reduction of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource or Demand Response Distributed Energy Resource Aggregation does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset or Distributed Energy Resource associated with the Demand Response Distributed Energy Resource Aggregation; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.15.8.2.3. Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency ~~measures~~ being zero, as specified in Section III.15.8.2.2(c)(i)).

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency ~~measures~~.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency ~~measures~~ being zero, as specified in Section III.15.8.2.2(c)(i)).

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency ~~measures~~.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency ~~measures~~ being zero, as specified in Section III.15.8.2.2(c)(i)).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency ~~measures~~.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.15.8.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of

whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

III.15.8.2.4. Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency ~~measures~~ being zero, as specified in Section III.15.8.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for a~~n On-Peak Demand Capacity Resource or a Seasonal~~ Passive Peak Demand Capacity Resource, the Capacity Supply Obligation associated with any Energy Efficiency ~~measures~~ shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.15.8.2.5. Capacity Performance Payment Rate.

The Capacity Performance Payment Rate shall be $9337/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.15.8.2.6. Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.15.8.3. Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.15.8.3.1 and Section III.15.8.3.2 below.

III.15.8.3.1. Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month shall be limited to an amount equal to the product of the applicable Capacity Auction Offer Price Cap multiplied by the resource's Capacity Supply Obligation for the Obligation Month.

III.15.8.3.2. ~~Annual~~ Seasonal Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [~~3~~ 2 months x (~~A~~SCAcp – ~~A~~CA~~sp~~opc) – (~~12~~ the number of months in the CCP x ~~A~~SCAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

~~A~~SCAcp = the Capacity Clearing Price for the relevant ~~Annual~~ Seasonal Capacity Auction.

~~ACAsp~~ CAopc = the ~~Annual~~ Capacity Auction Offer Price Cap for the relevant ~~Annual~~ Seasonal Capacity Auction.

CCP = Capacity Commitment Period

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the

Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.15.8.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month shall be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.15.8.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.15.8.3.2(b).

III.15.8.4. Allocation of Deficient or Excess Capacity Performance Payments.

For each type of Capacity Scarcity Condition as described in Section III.15.8.2.1 and for each Capacity Zone, the ISO shall allocate deficient or excess Capacity Performance Payments as described in subsections (a) and (b) below. Where more than one type of Capacity Scarcity Condition applies, then the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.

(a) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation Month, excluding any resources subject to the stop-loss mechanism described in Section III.15.8.3 for the Obligation Month and excluding any resource, or portion thereof, consisting of Energy Efficiency ~~measures~~. If the charge described in this Section III.15.8.4(a) causes a resource to reach the stop-loss limit described in Section III.15.8.3, then the stop-loss cap described in Section III.15.8.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.15.8.4(a).

(b) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is negative, the excess will be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency ~~measures~~) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.15.8.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result

of the application of the stop-loss mechanism described in Section III.15.8.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.15.8.4(b)

III.15.8.5. Charges to Market Participants with Capacity Load Obligations.

III.15.8.5.1. Calculation of Capacity Charges.

For purposes of this Section III.15.8.5.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in rate component (b) of Sections III.15.8.5.1.1 through III.15.8.5.1.8 shall be divided by the number of days in the month to derive a ~~daily settlement~~Daily Capacity Market Settlement value.

III.15.8.5.1.1. ~~Annual~~ Seasonal Capacity Auction Charge.

The S~~A~~CA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone S~~A~~CA Costs divided by Zonal Capacity Obligation.

Where:

Capacity Zone S~~A~~CA Costs, for each Capacity Zone, are the Total S~~A~~CA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total S~~A~~CA Costs are the sum of, for all Capacity Zones, Capacity Supply Obligations in each zone (the total obligation awarded to resources in the ~~Annual~~ Seasonal Capacity Auction process for the Obligation Month in the zone~~, excluding any obligations awarded to Intermittent Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.15.8.5.1.5~~) multiplied by the applicable clearing price from the auction in which the obligation was awarded to the resource, differentiating between Firm Gas Capacity Offer Portions and Non-firm Capacity Offer Portions as described in III.15.4.2.2(i)–(s).

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.15.8.5.1.2. Monthly Reconfiguration Auction Charge.

The monthly reconfiguration auction charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total Monthly Reconfiguration Auction Costs divided by Total Zonal Capacity Obligation.

Where:

Total Monthly Reconfiguration Auction Costs are the sum of, for all Capacity Zones, the product of Capacity Supply Obligations acquired through the Monthly Reconfiguration Auction in each zone and the applicable Monthly Reconfiguration Auction clearing price, minus the sum of, for all Capacity Zones, any Capacity Supply Obligations shed through the Monthly Reconfiguration Auction in each zone and the applicable Monthly Reconfiguration Auction clearing price.

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.15.8.5.1.3. HQICC Capacity Charge.

The HQICC capacity charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total HQICC Credits divided by Total Capacity Load Obligation.

Where:

Total HQICC credits are the product of HQICCs multiplied by the sum of the values calculated in Sections III.15.8.5.1.1(b), III.15.8.5.1.2(b), ~~III.15.8.5.1.5(b),~~ III.15.8.5.1.6(b), III.15.8.5.1.7(b), and III.15.8.5.1.8(b) in the Capacity Zone in which the HQ Phase I/II external node is located.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.15.8.5.1.4. Self-Supply Adjustment.

The self-supply adjustment is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) the Self-Supply Variance divided by Total Capacity Load Obligation.

Where:

Self-Supply Variance is the difference between foregone capacity payments and avoided capacity charges associated with designated self-supply quantities.

Foregone capacity payments to Self-Supplied Capacity Resources are the sum, for all Capacity Zones, of the product of the zonal Capacity Supply Obligation designated as self-supply, multiplied by the applicable clearing price from the auction in which the obligation was awarded, differentiating between Firm Gas Capacity Offer Portions and Non-Firm Gas Capacity Offer Portions as described in III.15.4.2.2(i)–(s).

Avoided capacity charges are the sum, for all Capacity Zones, of the product of any designated self-supply quantities multiplied by the sum of the values calculated in Sections III.15.8.5.1.1.(b), III.15.8.5.1.2(b), ~~III.15.8.5.1.5(b),~~ III.15.8.5.1.6(b), III.15.8.5.1.7(b) and III.15.8.5.1.8(b) in the Capacity Zone associated with the designated self-supply quantity.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.15.8.5.1.5. ~~Intermittent Power Resource Capacity Adjustment.~~[Reserved.]

~~The Intermittent Power Resource capacity adjustment in a winter season for the Obligation Months from October through May is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) the Intermittent Power Resource Seasonal Variance divided by Total Zonal Capacity Obligation.~~

~~Where:~~

~~Intermittent Power Resource Seasonal Variance is the difference between the ACA payments for Intermittent Power Resources in the Obligation Month and the base ACA payments for Intermittent Power Resources.~~

~~ACA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to Intermittent Power Resources in the Annual Capacity Auction process for the Obligation Month pursuant to Section III.15.4.2.3, multiplied by the applicable clearing price from the auction in which the obligation was awarded.~~

~~Base ACA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Annual Qualified Capacity procured from Intermittent Power Resources in the Annual Capacity Auction process, multiplied by the applicable clearing price from the auction in which the obligation was awarded.~~

~~Total Zonal Capacity Obligation is the total Zonal Capacity Obligation in all Capacity Zones.~~

III.15.8.5.1.6. CTR Transmission Upgrade Charge.

The CTR transmission upgrade charge is: (a) the Capacity Load Obligation in the Capacity Zones to which the applicable interface limits the transfer of capacity, multiplied by (b) Zonal CTR Transmission Upgrade Cost divided by Zonal Capacity Obligation.

Where:

Zonal CTR Transmission Upgrade Cost for each Capacity Zone to which the interface limits the transfer of capacity is the amount calculated pursuant to Section III.15.8.5.4.1(f), multiplied by the Zonal Capacity Obligation and divided by the sum of the Zonal Capacity Obligation for all Capacity Zones to which the interface limits the transfer of capacity.

III.15.8.5.1.7. CTR Pool-Planned Unit Charge.

The CTR Pool-Planned Unit charge is: (a) the total Capacity Load Obligation in all Capacity Zones less the amount of any CTRs specifically allocated pursuant to Section III.15.8.5.4.2, multiplied by (b) CTR Pool-Planned Unit Cost divided by Total Zonal Capacity Obligation less the amount of any CTRs specifically allocated pursuant to Section III.15.8.5.4.2.

Where:

The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.15.8.5.4.2(b).

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.15.8.5.1.8. Multi-Year Rate Election Adjustment.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where:

Zonal Multi-Year Rate Election Costs is the sum, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate multiplied by the Relative MRI of the resource (excluding any obligations procured in the Forward Capacity Auction that were terminated pursuant to Section III.13.3.4A or Section III.15.A.2.1, or withdrawn pursuant to Section III.15.A.2.3), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the most recent Handy-Whitman Index of Public Utility Construction Costs in effect as of the month prior to the start of ~~December 31 of the year preceding~~ the Capacity Commitment Period and divided by the Relative MRI of the resource) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, differentiating between Firm Gas Capacity Offer Portions and Non-Firm Gas Capacity Offer Portions as described in III.15.4.2.2(i) ~~–~~(s), multiplied by the Zonal Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation and divided by the Total Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning prior to June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where:

Zonal Multi-Year Rate Election Costs is the sum in each Capacity Zone, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate multiplied by the Relative MRI of the resource (excluding any obligations procured in the Forward Capacity Auction that were terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a

Capacity Supply Obligation (indexed using the most recent Handy-Whitman Index of Public Utility Construction Costs in effect as of ~~December 31 of the year preceding~~ the month prior to the start of the Capacity Commitment Period and divided by the Relative MRI of the resource) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, differentiating between Firm Gas Capacity Offer Portions and Non-Firm Gas Capacity Offer Portions as described in III.15.4.2.2(i)–(s).

III.15.8.5.2. Calculation of Capacity Load Obligation and Zonal Capacity Obligation.
The ISO shall assign each Market Participant a share of the Zonal Capacity Obligation prior to the commencement of each Obligation Month for each Capacity Zone established in the ~~Annual~~ Seasonal Capacity Auction pursuant to Section III.12.4. The Zonal Capacity Obligation of a Capacity Zone that contains a nested Capacity Zone shall exclude the Zonal Capacity Obligation of the nested Capacity Zone.

The Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations plus HQICCs; and (ii) the ratio of the sum of all load serving entities' ~~annual coincident contributions to the system-wide annual peak load~~ Coincident Peak Contribution in that Capacity Zone ~~from the calendar year one year prior to the start of the Capacity Commitment Period~~ to the system-wide sum of all load serving entities' ~~annual coincident~~ Coincident Peak ~~c~~Contributions ~~to the system-wide annual peak load from the calendar year one year prior to the start of the Capacity Commitment Period~~.

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with the receipt of electricity from the grid by Storage DARDs for later injection of electricity back to the grid; when all load of a Distributed Energy Resource Aggregation participating as a Storage DARD is load associated with the receipt of electricity from the grid for later injection of electricity back to the grid; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as a discrete Load Asset and is exclusively related to an Alternative Technology Regulation Resource following AGC Dispatch Instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A Market Participant's share of Zonal Capacity Obligation for each day of the month and each Capacity Zone shall equal the product of: (i) the Capacity Zone's Zonal Capacity Obligation as calculated above

and (ii) the ratio of the sum of the load serving entity's daily Coincident Peak Contributions, to the sum of all load serving entities' daily Coincident Peak Contributions in that Capacity Zone.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each day of the month and each Capacity Zone, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied Capacity Resource designations. A Capacity Load Obligation can be a positive or negative value.

A Market Participant's share of Zonal Capacity Obligation will not be reconstituted to include the demand reduction of a Demand Capacity Resource, Demand Response Resource, or a Demand Response Distributed Energy Resource Aggregation.

III.15.8.5.2.1. Charges Associated with Dispatchable Asset Related Demands.

Dispatchable Asset Related Demand resources will not receive ~~Annual~~ Seasonal Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.15.8.5.3. Excess Revenues.

Any payment associated with a Capacity Supply Obligation Bilateral that was to accrue to a Capacity Acquiring Resource for a Capacity Supply Obligation that is terminated pursuant to Section III.13.3.4A or Section III.15.A.2.1, or withdrawn pursuant to Section III.15.A.2.3, shall instead be allocated to Market Participants based on their pro rata share of all Capacity Load Obligations in the Capacity Zone in which the terminated resource is located.

III.15.8.5.4. Capacity Transfer Rights.

III.15.8.5.4.1. Specifically Allocated CTRs Associated with Transmission Upgrades.

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.15.8.5.1.6.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.15.8.5.1.6.

(e) **Maine Export Interface**. Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine export interface for as long as Casco Bay continues to pay to support the transmission upgrades.

(f) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price in the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price in the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. This value will be divided by the number of days in the month to derive a daily settlement value.

III.15.8.5.4.2. Specifically Allocated CTRs for Pool-Planned Units.

(a) In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive for each Capacity Commitment Period an allocation of CTRs for each such unit that is the product of: (i) the MW quantity of capacity that the unit cleared in the ~~Annual~~ Seasonal Capacity Auction associated with the Capacity Commitment Period; and (ii) the municipal utility's ownership entitlements in such unit. The CTRs allocated pursuant to this Section may be designated as self-supply quantities as described in

Section III.15.2.7~~9~~. Municipal utility ownership entitlements are set as shown in the table below and are not transferrable

	Millstone 3	Seabrook	Stonybrook GT 1A	Stonybrook GT 1B	Stonybrook GT 1C	Stonybrook 2A	Stonybrook 2B	Wyman 4
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%

Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%
Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%
Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%

Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%

Allocation of CTRs as described in this Section shall expire on December 31, 2040. If a unit listed in the table above retires prior to December 31, 2040, however, allocation of CTRs for such unit shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for ~~Annual or~~ Seasonal Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant (collectively, "WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

(b) For any CTRs specifically allocated pursuant to this Section that are not designated self-supply quantities for the Capacity Commitment Period, the municipal utility entitlement holder shall receive a credit reflecting the value of such remaining CTRs. The value of each remaining CTR shall be calculated as the product of: (i) the Capacity Clearing Price for the Capacity Zone where the load of the municipal utility entitlement holder is located minus the Capacity Clearing Price for the Capacity Zone in which the Pool-Planned Unit is located; and (ii) the remaining MW quantity. This value will be divided by the number of days in the month to derive a daily settlement value.

III.15.8.5.5. ~~Annual or~~ Seasonal Capacity Market Net Charge Amount.

~~The Annual or~~ Seasonal Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charges; (b) its revenues from any applicable specifically allocated CTRs; and (c) any applicable export charges.

III.15.8.6. Internal Bilateral for Capacity Settlement.

For Market Participants that have submitted an Internal Bilateral for Capacity, the Daily Capacity Market Settlement shall include a payment or charge based on the monthly payment rate associated with the agreed upon payment type in the relevant Capacity Zone for the submitted monthly MW quantity for the duration of the Internal Bilateral for Capacity. This value will be divided by the number of days in the month to derive the Daily Capacity Market Settlement.

III.15.9. Information Publication and Reporting.

III.15.9.1. Publication of Certain Data Prior to the ~~Annual~~ Seasonal Capacity Auction.

For each ~~Annual~~ Seasonal Capacity Auction, no later than one Business Day before the opening of the ~~Annual~~ Capacity Auction Offer Window, the ISO shall publish publicly on its website:

a. which Capacity Zones shall be modeled in the ~~Annual~~ Seasonal Capacity Auction;
b. the transmission interface limits as determined pursuant to Section III.12.5;
c. which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the ~~Annual~~ Seasonal Capacity Auction;
d. determinations on which ~~new~~ resources have been rejected from the Seasonal Capacity Auction due to deliverability impacts pursuant to Section III.15.2.3;
e. the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the ~~Annual~~ Seasonal Capacity Auction, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone;
f. for each resource that submitted a Load-Side Relationship Certification, the following information: the resource technology type; which qualifying circumstance in Section III.A.21.1.4 was asserted in the Load-Side Relationship Certification; the relevant state policy asserted in the Load-Side Relationship Certification, if any; whether the ISO accepted or rejected the Load-Side Relationship Certification; and, consequently, whether the resource was subject to a review for the exercise of buyer-side market power; and
g. which resources are qualified to participate in the ~~Annual~~ Seasonal Capacity Auction, including resource type, Capacity Zone, and ~~Annual Qualified Capacity~~ Maximum Capability.

III.15.9.2. Publication of Certain Data After Conducting the ~~Annual~~ Seasonal Capacity Auction.

In addition to the ~~Annual~~ Seasonal Capacity Auction results information identified by Section III.15.2.11 and Section III.15.4.3 of Market Rule 1, within 15 days of conducting the ~~Annual~~ Seasonal Capacity Auction, the ISO shall publish publicly on its website:

a. which Capacity Offers, satisfying the requirements of Section III.A.21.1 of Market Rule 1, were not reviewed for an exercise of buyer-side market power because of one of the conditions described in Sections III.A.21.1.1, III.A.21.1.2, or III.A.21.1.4 of Market Rule 1; and the condition met by each such resource;
b. the Internal Market Monitor's determinations made as part of any buyer-side market power review conducted pursuant to Section III.A.21.2 and any Capacity Offer Floor Price

determinations made pursuant to Section III.A.21.3 with regard to capacity not previously ~~cleared~~ offered in a~~n Annual~~ like-season Seasonal Capacity Auction or Forward Capacity Auction, and the basis for any such determinations; except that offer price information and any information employed by the Internal Market Monitor in making these determinations related to the potential impact of a Capacity Resource's offer on Capacity Clearing Prices shall not be published publicly;

c. the Internal Market Monitor's determinations regarding Proposed Capacity Offers, including whether the Internal Market Monitor accepted or rejected prices specified in a resource's Proposed Capacity Offer that were subject to Internal Market Monitor review and whether the Internal Market Monitor accepted or rejected the cost components of the resource' offer, which are set forth in Section III.A.22.2.3(a). No offer prices, cost components, or other underlying data shall be published; and~~,~~

d. which resources offering capacity not previously offered into a~~n Annual~~ Seasonal Capacity Auction or Forward Capacity Auction were qualified to participate in the ~~Annual~~ Seasonal Capacity Auction (this information will include a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations).

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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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 resource's energy market offer obligation pursuant to III.15.7.1. ~~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 Maximum Capability~~Seasonal Claimed Capability~~ value in proportion to the total of the Maximum Capabilities~~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:

(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 a~~n~~ Seasonal~~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 a~~n~~ like-season Seasonal~~Annual~~ Capacity Auction.

(b) For the purposes of this Section III.A.21, capacity not previously offered into a~~n~~ Seasonal~~Annual~~ Capacity Auction includes the following:

(i) capacity supplied from a resource that has never been offered into a~~n~~ Forward Capacity Auction or Seasonal~~Annual~~ Capacity Auction;

(ii) capacity supplied from a resource previously offered into a Forward Capacity Auction or Seasonal~~n Annual~~ Capacity Auction, where such capacity represents an increase to the Maximum Capability calculated pursuant to Section III.15.3(b)~~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 a~~n~~ Seasonal~~Annual~~ Capacity Auction since deactivation or retirement.

(c) For the purposes of this Section III.A.21, capacity not previously offered into a~~n~~ Seasonal~~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 Seasonal~~Annual Capacity Auction or Forward Capacity Auction ~~while backed by that contract; or~~

~~(ii)~~ for the purpose of the ~~Annual~~ Seasonal 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 a~~n~~ Seasonal~~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 a~~n Annual Qualified Capacity~~ summer Maximum Capability or winter Maximum Capability of 5 MW.

III.A.21.1.2. Passive Demand ~~Response~~ Capacity Resources.

Capacity not previously offered into a~~n Annual~~ Seasonal Capacity Auction that will be included in a Capacity Offer and that is supplied from an ~~On-Peak Demand Capacity Resource or Seasonal Peak~~Passive 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 a~~n Annual~~ Seasonal 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 one or more~~a single~~ new External Resource(s), and the External Resource(s) or import capacity supplied by the External Resource(s) 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 a~~n~~ Seasonal~~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 a~~n~~ Seasonal~~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) to the extent necessary to conduct a review for the exercise of buyer-side market power, as described in Section III.A.21.2, or to calculate a Capacity Offer Floor Price, as described in Section III.A.21.3;

(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 a~~n Annual~~Seasonal 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~~ Seasonal 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~~For capacity that will be offered into a Summer Capacity Auction associated with the Capacity Commitment Period beginning on May 1, 2030 or any Summer Capacity Auction thereafter, the Lead Market Participant may submit the

information required by subsection (a) as early as the first Business Day of ~~January~~ December of the fourth~~third~~ calendar year prior to the first ~~Annual~~ Summer 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 a Winter Capacity Auction associated with the Capacity Commitment Period beginning on November 1, 2029 or any Winter Capacity Auction thereafter, the Lead Market Participant may submit the information required by subsection (a) as early as the first Business Day of June of the third calendar year prior to the first Winter 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~~ Summer Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, the Winter Capacity Auction associated with the Capacity Commitment Period beginning on November 1, 2028, or the Summer Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2029, the earliest submission date ~~will be~~is the first Business Day of June 2026.

(c) For capacity that will be offered into the Summer Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, ~~I~~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 1, 2027 ~~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~~. For capacity that will be offered into a Summer Capacity Auction associated with the Capacity Commitment Period beginning on May 1, 2029 or any Summer Capacity Auction thereafter, 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 May of the calendar year prior to the first Summer Capacity Auction into which the capacity will be offered pursuant to Section III.A.22.1. For capacity that will be offered into a Winter Capacity Auction, 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 November of the calendar year prior to the first Winter 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~~ Seasonal 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~~ Seasonal 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 Seasonal~~Annual~~ Capacity Auction to withdraw the Load-Side Relationship Certification if, at any point through the time of the Seasonal~~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. The window to withdraw a Load-Side Relationship Certification shall close two Business Days before the first day of the Capacity Auction Offer Window. If 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 after the window to withdraw a Load-Side Relationship Certification closes and before the posting of the results of the Seasonal Capacity Auction, the Lead Market Participant must notify the ISO and justify the change in circumstances. 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, for capacity that will be offered into a Summer Capacity Auction, the withdrawal occurs no later than the first Business Day of MayJune of the calendar year prior to the SeasonalAnnual Capacity Auction, or if, for capacity that will be offered into a Winter Capacity Auction, the withdrawal occurs no later than the first Business Day of November of the calendar year prior to the Winter 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. Notwithstanding the foregoing, for capacity that will be offered into the Summer Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, the requirements of this Section III.A.21.1.5.(f)(1) apply if the withdrawal occurs no later than the first Business Day of June of the calendar year prior to the Summer Capacity Auction.

(ii) If, for capacity that will be offered into a Summer Capacity Auction, the withdrawal occurs later than the first Business Day of JuneMay of the calendar year prior to the Annual Seasonal Capacity Auction, or if, for capacity that will be offered into a Winter Capacity Auction, the withdrawal occurs later than the first Business Day of November of the calendar year prior to the Winter 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). Notwithstanding the foregoing, if, for capacity that will be offered into the Summer Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, the withdrawal occurs later than the first Business Day of June of the calendar year prior to the Summer 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 Seasonal~~Annual~~ Capacity Auction to submit a Load-Side Relationship Certification if, at any point through the time of the ~~Annual~~ Seasonal 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~~ Seasonal 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~~Seasonal Capacity Auction clearing prices resulting from entry of the capacity in the ~~Annual~~Seasonal 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 a~~n~~ Seasonal~~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 a~~n~~ Seasonal~~Annual~~ Capacity Auction, the Internal Market Monitor shall determine a break-even price for the capacity in relation to a year of capacity market revenues that excludes consideration of out-of-market revenues, as those are defined in Section III.A.21.3(a)(ii). To determine the break-even price the Internal

Market Monitor shall~~by~~ enter~~ing~~ 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 calculat~~eing~~ the ~~break-even~~annualized capacity market revenue contribution required from ~~the Annual~~a Summer Capacity Auction and a Winter Capacity Auction ~~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~~annualized capacity market revenue 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 Seasonal~~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 a~~n~~ Seasonal~~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~~ MRI Capacity ~~V~~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~~ MRI Capacity v~~V~~alues. 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~~by the date identified on the Capacity Auction Calendar. ~~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 Seasonal~~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 Seasonal~~Annual~~ Capacity Auction into which the capacity is being offered that equals the Capacity Auction Offer Price Cap calculated for such Seasonal~~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 a~~n~~ Seasonal~~Annual~~ Capacity Auction, except as follows:

(i) If the capacity for which a Capacity Offer Floor Price has been determined does not clear a~~the first~~ Seasonal~~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 Seasonal~~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 Seasonal~~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.

(iv) If the remaining annualized capacity market revenue contribution calculated pursuant to Section III.A.21.3(a) and updated pursuant to Section III.A.21.3(i) is less than or equal to $0, the capacity will no longer be subject to a Capacity Offer Floor Price.

(i) Prior to each Seasonal Capacity Auction, the Internal Market Monitor shall update the break-even price used to calculate a Capacity Offer Floor Price to account for any revenues received through Capacity Supply Obligations obtained by capacity subject to a Capacity Offer Floor Price through a previous Seasonal Capacity Auction.

(i) For any capacity subject to a Capacity Offer Floor Price offered into a Seasonal Capacity Auction that is awarded a Capacity Supply Obligation through a Seasonal Capacity Auction, the Internal Market Monitor will calculate the remaining annualized necessary capacity market revenue by subtracting such capacity's Seasonal Capacity Auction revenue paid pursuant to Section III.15.8.1.1 from the value developed in III.A.21.3(a).

(ii) The Internal Market Monitor will recalculate the break-even price applied to capacity that remains subject to a Capacity Offer Floor Price using the remaining annualized capacity market contribution as determined in Section III.A.21.3(a), and the total quantity of summer Seasonal MRI Capacity and winter Seasonal MRI Capacity that remains subject to a Capacity Offer Floor Price.

(iii) The Internal Market Monitor shall notify the Lead Market Participant of any update to the Capacity Offer Floor Price by the relevant date as published on the Capacity Auction Calendar for the relevant Seasonal Capacity Auction.

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~~ Seasonal Capacity Auction is required to participate in the qualification process for the ~~Annual~~ Seasonal 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~~ Seasonal Capacity Auction is required to participate in the qualification process for the ~~Annual~~ Seasonal Capacity Auction as described in Sections III.15.2 and III.15.3:

a. For a Summer Capacity Auction, 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~~ February 1 of the same calendar year as the ~~Annual~~ Summer Capacity Auction.

~~a.~~b. For a Winter Capacity Auction, 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 August 1 of the same calendar year as the Winter Capacity Auction.

~~(b)~~(c) A Capacity Offer must be submitted to the ISO during the ~~Annual~~ Capacity Auction Offer Window for the Summer Capacity Auction for a resource that participates in the qualification process for the Summer~~Annual~~ Capacity Auction as described in Sections III.15.2 and III.15.3 and receives a~~n~~ summer Seasonal~~Annual~~ ~~Qualified~~ MRI Capacity value greater than 0 MW. The Capacity Offer must include a total quantity that is equal to the resource's ~~Annual Qualified~~summer Seasonal MRI Capacity. A Capacity Offer must be submitted to the ISO during the Capacity Auction Offer Window for the Winter Capacity Auction for a resource that participates in the qualification process for the Winter Capacity Auction as described in Sections III.15.2 and III.15.3 and receives a winter Seasonal MRI Capacity value greater than 0 MW. The Capacity Offer must include a total quantity that is equal to the resource's winter Seasonal MRI 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~~ Seasonal Capacity Auction with the resource's Seasonal~~Annual~~ ~~Qualified~~ MRI 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.

~~(e)~~(e) Capacity that is rejected from the Seasonal Capacity Auction due to a Lead Market Participant's failure to satisfy the Auction Delivery Financial Assurance requirements set forth in Section VIII.A of the ISO New England Financial Assurance Policy may be reviewed by the Internal Market Monitor for the potential exercise of market power. The Internal Market Monitor may request additional information from the Lead Market Participant as necessary to make such a determination and may take any appropriate action, including referral to the Commission's Office of Enforcement in accordance with Section III.A.19 as a potential Market Violation.

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 Seasonal~~Annual~~ Capacity Auction as described in this Section III.A.22.2.

III.A.22.2.1. Capacity Offer Price Threshold.

For each ~~Annual~~ Seasonal 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 like-season Summer~~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~~ Seasonal Capacity Auction intersects the System-Wide Capacity Demand Curve for the upcoming Seasonal~~Annual~~ Capacity Auction that is filed with the Commission pursuant to Section III.12.3(a) in advance of the upcoming ~~Annual~~ Seasonal Capacity Auction.

(b) The preliminary value of the Capacity Offer Price Threshold shall not be higher than 75 percent of the Net CONE value pursuant to Section III.15.1.2 for the upcoming Seasonal~~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 pursuant to Section III.15.1.2 for the upcoming ~~Annual~~ Seasonal Capacity Auction.

(c) A margin value shall be calculated using the following formula:

$$Margin = \$1 \times \frac{0.75 \times netCONE_{upcoming\ SCA} - COPT_{preliminary}}{0.75 \times netCONE_{upcoming\ SCA}}$$

~~$$Margin = \$1/kW\text{-}month \times \left[\frac{(0.75 \times Net\ CONE_{upcoming\ ACA}) - COPT_{preliminary}}{(0.75 \times Net\ CONE_{upcoming\ ACA})}\right]$$~~

(d) The final value of the Capacity Offer Price Threshold for the upcoming Seasonal~~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.22.2.1.A Capacity Offer Price Threshold Transition.

(a) Notwithstanding Section III.A.22.2.1 above, for the Summer Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028 and the Winter Capacity Auction associated with the Capacity Commitment Period beginning on November 1, 2028, the Capacity Offer Price Threshold shall be calculated using the following formula:

$$COPT^{2028/2029} = 0.37 \times Net\ CONE^{2028/2029}$$

~~$COPT(2028/2029) = 0.37 \times Net\ CONE(2028/2029)$~~

Where

Net ~~CONE (2028/2029)~~CONE$^{2028/2029}$ = the final annualized Net CONE value corresponding with the Capacity Commitment Periods beginning on June 1, 2028 and November 1, 2028 pursuant to Section III.15.1.2.1(b).

(b) Notwithstanding Section III.A.22.2.1 above, for the Summer Capacity Auction associated with the Capacity Commitment Period beginning on May 1, 2029 and the Winter Capacity Auction associated with the Capacity Commitment Period beginning on November 1, 2029, the Capacity Offer Price Threshold shall be calculated using the following formula:

$$COPT^{2029/2030} = \frac{\left(\frac{Clearing\ Price^{2028/2029}}{Net\ CONE^{2028/2029}} + 0.42\right)}{2} \times Net\ CONE^{2029/2030}$$

~~$COPT = \frac{\left(\frac{Clearing\ Price(2028/2029)}{Net\ CONE(2028/2029)} + 0.42\right)}{2} \times Net\ CONE(2029/2030)$~~

Where

$Clearing\ Price^{2028/2029}$ ~~Clearing Price~~ ~~(2028/2029)~~ the like-season Capacity Clearing Price for the Rest-of-Pool Capacity Zone (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) for the Summer Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028 or the Winter Capacity Auction associated with the Capacity Commitment Period beginning on November 1, 2028.

$Net\ CONE^{2028/2029}$ ~~Net CONE (2028/2029) =~~ the final annualized Net CONE value corresponding with the Capacity Commitment Periods beginning on June 1, 2028 and November 1, 2028, pursuant to Section III.15.1.2.1(b).

~~.~~ $Net\ CONE^{2029/2030}$ ~~Net CONE (2029/2030) =~~ the final annualized Net CONE value corresponding with the Capacity Commitment Periods beginning on May 1, 2029 and November 1, 2029, pursuant to Section III.15.1.2.1(b).

(c) Notwithstanding Section III.A.22.2.1 above, for the Summer Capacity Auction associated with the Capacity Commitment Period beginning May 1, 2030 and the Winter Capacity Auction associated with the Capacity Commitment Period beginning November 1, 2030, the Capacity Offer Price Threshold shall be calculated using the following formula:

$$COPT^{2030/2031} = \frac{\left(\frac{Clearing\ Price^{2028/2029}}{Net\ CONE^{2028/2029}} + \frac{Clearing\ Price^{2029/2030}}{Net\ CONE^{2029/2030}}\right)}{2} \times Net\ CONE^{2030/2031}$$

~~$COPT = \frac{\left(\frac{Clearing\ Price(2028/2029)}{Net\ CONE(2028/2029)} + \frac{Clearing\ Price(2029/2030)}{Net\ CONE(2029/2030)}\right)}{2} \times Net\ CONE(2029/2030)$~~

Where

$Clearing\ Price^{2028/2029}$ ~~Clearing Price (2028/2029) =~~ the like-season Capacity Clearing Price for the Rest-of-Pool Capacity Zone (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) for the Summer Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028 or the Winter Capacity Auction associated with the Capacity Commitment Period beginning on November 1, 2028.

$Clearing\ Price^{2029/2030}$ ~~Clearing Price (2029/2030) =~~ the like-season Capacity Clearing Price for the Rest-of-Pool Capacity Zone (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) for the Summer Capacity Auction associated with the Capacity Commitment Period beginning on May 1, 2029 or the Winter Capacity Auction associated with the Capacity Commitment Period beginning on November 1, 2029.

$Net\ CONE^{2028/2029}$ ~~Net CONE (2028/2029)~~ = the final annualized Net CONE value corresponding with the Capacity Commitment Periods beginning on June 1, 2028 and November 1, 2028, pursuant to Section III.15.1.2.1(b).

$Net\ CONE^{2029/2030}$ ~~Net CONE (2029/2030)~~ = the final annualized Net CONE value corresponding with the Capacity Commitment Periods beginning on May 1, 2029 and November 1, 2029, pursuant to Section III.15.1.2.1(b).

$Net\ CONE^{2030/2031}$ ~~Net CONE (2030/2031)~~ = the final annualized Net CONE value corresponding with the Capacity Commitment Periods beginning on May 1, 2030 and November 1, 2030, pursuant to Section III.15.1.2.1(e).

(d) Notwithstanding Section III.A.22.2.1 above, for the Summer Capacity Auction associated with the Capacity Commitment Period beginning May 1, 2031 and the Winter Capacity Auction associated with the Capacity Commitment Period beginning November 1, 2031, the Capacity Offer Price Threshold shall be calculated using the following formula:

$$COPT^{2031/2032} = \frac{\left(\frac{Clearing\ Price^{2029/2030}}{Net\ CONE^{2029/2030}} + \frac{Clearing\ Price^{2030/2031}}{Net\ CONE^{2030/2031}}\right)}{2} \times Net\ CONE^{2031/2032}$$

Where

$Clearing\ Price^{2029/2030}$ = the like-season Capacity Clearing Price for the Rest-of-Pool Capacity Zone (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) for the Summer Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2029 or the Winter Capacity Auction associated with the Capacity Commitment Period beginning on November 1, 2029.

$Clearing\ Price^{2030/2031}$ = the like-season Capacity Clearing Price for the Rest-of-Pool Capacity Zone (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) for the Summer Capacity Auction associated with the Capacity Commitment Period beginning on May 1, 2030 or the Winter Capacity Auction associated with the Capacity Commitment Period beginning on November 1, 2030.

Net CONE$^{2029/2030}$ = the final annualized Net CONE value corresponding with the Capacity Commitment Periods beginning on May 1, 2029 and November 1, 2029, pursuant to Section III.15.1.2.1(b).

Net CONE$^{2030/2031}$ = the final annualized Net CONE value corresponding with the Capacity Commitment Periods beginning on May 1, 2030 and November 1, 2030, pursuant to Section III.15.1.2.1(e).

Net CONE$^{2031/2032}$ = the final annualized Net CONE value corresponding with the Capacity Commitment Periods beginning on May 1, 2031 and November 1, 2031, pursuant to Section III.15.1.2.1(e), adjusted, as appliable, in accordance with Section III.15.1.2.2(a).

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~~ Seasonal 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~~ Seasonal 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~~ Seasonal 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~~ Seasonal 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~~ Price 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:

$$\textit{Net Going Forward Costs}_{season} = \frac{(GFC_{season} - IMR_{season})}{(MRIC\,CQ_{season\,Summer,}\ kW) \times (12\,6\ months)}$$

Where:

GFC_{season} = seasonal~~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. For going forward costs that are necessary for the resource's operation over two consecutive Capacity Commitment Periods and are avoidable for the Capacity Commitment

Period associated with the Proposed Capacity Offer, a portion of these costs consistent with the proportion of the resource's combined winter Seasonal MRI Capacity and summer Seasonal MRI Capacity, less expected inframarginal rents across both seasons, may be included in the Proposed Capacity Offer.

~~CQ~~MRIC$_{season}$~~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~~Seasonal MRI Capacity.

IMR$_{season}$ = expected ~~annual~~ seasonal 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 Price~~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, effective Performance Payment Rate, 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 Price~~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~~ in other costs components of the Proposed Capacity Offer 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~~ Seasonal 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 Price~~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 Price~~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 Seasonal~~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~~ Seasonal Capacity Auction. If the lowest composite cost ~~segment~~portion determined by the above process includes both firm capacity and non-firm gas capacity, each will be included as a non-rationable ~~segment~~portion, consistent with Section III.15.4, at the calculated price.

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 (seasons~~years~~)**	**Semi-Annual Rate of Capital Cost Recovery**
1 to 5	~~3~~60	0.053~~106~~
6 to 10	~~2~~50	0.055~~110~~
11 to 15	~~2~~40	0.058~~117~~
16 to 20	~~15~~30	0.065~~131~~
21 to 25	~~1~~20	0.080~~163~~
25 plus	~~5~~10	0.130~~264~~

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's semi-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 semi-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 semi-annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{CostOfCapital}{(1-(1+CostOfCapital)^{-RemainingLife})}$$

Where:

Cost Of Capital = the adjusted semi-annual 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~~ MRI Capacity Notification Date for the ~~Annual~~ Seasonal 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 MRI~~Qualified~~ Capacity ~~V~~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 Seasonal~~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~~ Seasonal 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 Seasonal~~Annual~~ Capacity Auction; and

(c) some portion of the MWs ~~quantity~~ specified in such price-quantity pair that is also included in the Capacity Offer's Above-Threshold Offer ~~Segment~~ Portion must have been awarded a Capacity Supply Obligation in the Seasonal~~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~~ Seasonal 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~~ MWs 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~~ Seasonal 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~~Seasonal 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~~ MWs 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 MWs ~~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 Seasonal ~~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 Seasonal ~~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~~ number of 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~~ Seasonal 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~~ Seasonal 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~~ Seasonal MRI~~Qualified~~ Capacity, the ability to meet the relevant requirement is less than the requirement.

For the purpose of performing the pivotal supplier test as described in this Section III.A.23.1:

(a) "Pivotal Supplier Test Non-Firm Gas Capacity" is the Seasonal MRI Capacity from Generating Capacity Resources subject to the Gas Availability Constraint.

(b) "Pivotal Supplier Test Identified Capacity" is the Seasonal MRI Capacity from: (i) Generating Capacity Resources, excluding Pivotal Supplier Test Non-Firm Gas Capacity, and (ii) Demand Capacity Resources.

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.

This Section III.A.23.1.1 describes the calculation of the system-level requirement for both Summer Capacity Auctions and Winter Capacity Auctions. For Winter Capacity Auctions, the quantity of Pivotal Supplier Test Non-Firm Gas Capacity that counts towards the ability to meet the relevant requirement respects both the Maximum Capacity Limit for Gas Constrained Winter Capacity, as calculated in accordance with Section III.12.2.3, and any applicable zonal Maximum Capacity Limits. When evaluating the ability to meet the system-level requirement for a Winter Capacity Auction, the test accounts first for Pivotal Supplier Test Non-Firm Gas Capacity in each import-constrained Capacity Zone, second for Pivotal Supplier Test Non-Firm Gas Capacity in the Rest-of-Pool Capacity Zone, and, finally, for Pivotal Supplier Test Non-Firm Gas Capacity in each export-constrained and nested export-constrained Capacity Zones, simultaneously.

At the system level, the ability to meet the relevant requirement is the sum of the following:

~~(d) The total Annual Qualified Capacity from all Generating Capacity Resources and Demand Capacity Resources in the Rest-of-Pool Capacity Zone;~~

(a) For each modeled import-constrained Capacity Zone, the greater of:

(1) the Local Sourcing Requirement of the import-constrained Capacity Zone;

(2) the sum of:

a. the total ~~Annual Qualified Capacity from all Generating Capacity Resources and Demand Capacity Resources~~Pivotal Supplier Test Identified Capacity 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~~ Seasonal MRI~~Qualified~~ Capacity from Import Capacity Resources over the interface, and;

b. the lesser of:

(i) the Maximum Capacity Limit for Gas Constrained Winter Capacity; and

(ii) the Pivotal Supplier Test Non-Firm Gas Capacity within the import-constrained Capacity Zone.

~~e. the Local Sourcing Requirement of the import-constrained Capacity Zone;~~

(b) For the Rest-of-Pool Capacity Zone, the sum of:

a. The ~~total Annual Qualified Capacity from all Generating Capacity Resources~~Pivotal Supplier Test Identified Capacity ~~and Demand Capacity Resources~~ in the Rest-of-Pool Capacity Zone; and

b. The lesser of:

i. the Pivotal Supplier Test Non-Firm Gas Capacity within the Rest-of-Pool Capacity Zone; and

ii. the greater of: 0 and, as described in Section III.A.23.1.1(a)(2)(b), the difference between the Maximum Capacity Limit for Gas Constrained Winter Capacity and the Pivotal Supplier Test Non-Firm Gas Capacity within each import-constrained Capacity Zone.

~~(e) 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;~~

(c~~d~~)For each modeled export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, the lesser of:

(1) the Maximum Capacity Limit of the export-constrained Capacity Zone; and

(2) the sum of:

a. the total ~~Annual Qualified Capacity from all Generating Capacity Resources and Demand Capacity Resources~~Pivotal Supplier Test Identified Capacity within the export-

constrained Capacity Zone, excluding the total ~~Annual Qualified Capacity from Generating Capacity Resources and Demand Capacity Resources~~Pivotal Supplier Test Identified Capacity within an associated 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~~ Seasonal MRI~~Qualified~~ Capacity from Import Capacity Resources over the interface, and;

b. the least of:

a. Pivotal Supplier Test Non-Firm Gas Capacity in the export-constrained Capacity Zone, excluding Pivotal Supplier Test Non-Firm Gas Capacity located in any associated nested-export constrained Capacity Zone;

b. the greater of 0 and the difference between the Maximum Capacity Limit for Gas Constrained Winter Capacity and the sum of

i. Section III.A.23.1.1(a)(2)(b), and

ii. Section III.A.23.1.1(b)(2).

c. the greater of 0 and the difference between the Maximum Capacity Limit of the export-constrained Capacity Zone and the sum of:

i. the value calculated in Section III.A.23.1.1~~.~~(c)(2)(a), and

ii. for any associated nested export-constrained Capacity Zone, the lesser of (i) the value calculated in Section III.A.23.1.1(d)(1) and (ii) the value calculated in Section III.A.23.1.1(d)(2)(a); and

c. The contribution from any associated nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1.1(d).

~~(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);~~

(d) For each modeled nested export-constrained Capacity Zone, the lesser of:

(1) the Maximum Capacity Limit of the nested export-constrained Capacity Zone;

(2~~1~~) the sum of:

a. the total ~~Annual Qualified Capacity from all Generating Capacity Resources and Demand Capacity Resources~~Pivotal Supplier Test Identified Capacity 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 Seasonal MRI ~~Annual Qualified~~ Capacity from Import Capacity Resources over the interface, and;

b. the least of:

a. Pivotal Supplier Test Non-Firm Gas Capacity in the nested export-constrained Capacity Zone;

b. the greater of 0 and the difference between the Maximum Capacity Limit for Gas Constrained Winter Capacity and the sum of Sections III.A.23.1.1(a)(2)(b), III.A.23.1.1(b)(2), and III.A.23.1.1~~.~~(c)(2)(b);~~.~~

c. the greater of 0 and the difference between the Maximum Capacity Limit of the nested export-constrained Capacity Zone and the value calculated in Section III.A.23.1.1(d)(2)(a).

~~(2) the Maximum Capacity Limit of the nested export-constrained Capacity Zone;~~

(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~~Seasonal MRI Capacity from Import Capacity Resources over the interface.

(f) If there are multiple import-constrained Capacity Zones modeled for a Winter Capacity Auction, the total Pivotal Supplier Test Non-Firm Gas Capacity counted to meet the relevant requirement pursuant to Section III.A.23.1.1(a) shall not exceed the Maximum Capacity Limit for Gas Constrained Winter Capacity.

~~(f)~~(g) If there are multiple non-nested export-constrained Capacity Zones modeled for a Winter Capacity Auction, the total Pivotal Supplier Test Non-Firm Gas Capacity counted to meet the relevant requirement shall be calculated in such a way that: (i) maximizes the total Pivotal Supplier Test Non-Firm Gas Capacity counted to meet the relevant requirement across all export-constrained and nested export-constrained Capacity Zones, subject to the calculations described in Sections III.A.23.1.1(c) and III.A.23.1.1(d); and (ii) ensures the total Pivotal Supplier Test Non-Firm Gas Capacity counted to meet the relevant requirement does not exceed the Maximum Capacity Limit for Gas Constrained Winter Capacity.

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~~Pivotal Supplier Test Identified Capacity located within the import-constrained Capacity Zone; ~~and~~

~~(b)~~ (b) The lesser of (i) the Pivotal Supplier Test Non-Firm Gas Capacity within the import-constrained Capacity Zone, and (ii) the Maximum Capacity Limit for Gas Constrained Winter Capacity; and

~~(b)~~(c) 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~~Seasonal MRI Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

~~Annual Qualified~~Seasonal MRI 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~~Seasonal MRI 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 Pivotal Supplier Test Non-Firm Gas Capacity in an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1.1(a) for that import-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.

(c) If the removal of a supplier's Pivotal Supplier Test Non-Firm Gas Capacity in the Rest-of-Pool Capacity Zone does not change the quantity calculated in Section III.A.23.1.1(b), then that capacity is treated as capacity of a non-pivotal supplier.

~~(b)~~(d) If the removal of a supplier's ~~Annual Qualified~~Seasonal MRI 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)~~(e) If the removal of a supplier's ~~Annual Qualified~~Seasonal MRI 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.

(f) If the removal of a supplier's Pivotal Supplier Test Non-Firm Gas Capacity in an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1.2 for that import-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.

~~(d)~~(g) If a supplier whose only ~~Annual Qualified~~Seasonal MRI Capacity is a single C~~c~~apacity R~~r~~esource with a Capacity Offer that (i) is not subject to rationing, and (ii) contains only one price-quantity pair for the entire ~~Annual Qualified~~Seasonal MRI 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~~ Seasonal Capacity Auction results are determined.

III.A.23.4. ~~Qualified~~ Seasonal MRI 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~~Seasonal MRI 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 Seasonal MRI~~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 of CNR Capability, CNI Capability, or equivalent CNR Capability in any single Capacity Commitment Period, 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. Lead Market Participants submitting a Deactivation Notification shall provide a description of any subsequent Deactivation Notifications planned for submission by that Lead Market Participant on, or prior to, the next subsequent Deactivation Notification Deadline. 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 of CNR Capability, CNI Capability, or equivalent CNR Capability in any single Capacity Commitment Period, 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) full deactivation of the only resource controlled by a Lead Market Participant or its Affiliates participating in the ~~Annual~~ Capacity Market; or (b) full

deactivation of all the 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~~Seasonal MRI 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~~ MRI Capacity (in kilowatts) and ~~12~~ the number of months in the Capacity Commitment Period.

The Capacity Resource's net ~~annual~~ expected cash flow for ~~the first~~ any Capacity Commitment Period of the resource's remaining economic life (i.e., the Capacity Commitment Periods 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~~ ~~c~~Capacity ~~r~~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 Period~~s~~ 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 Capacity Commitment Period to ~~five years~~ ten Capacity Commitment Periods ~~with year one being~~ beginning with the Capacity Commitment Period ~~associated with~~ of deactivation identified in 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~~ Capacity Commitment Period 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 Capacity Performance Payment and related inputs, including 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 Seasonal 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 as modified by the adjusted composite costs described in this Section III.A.24.4.4 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.

III.A.24.5.1 First Capacity Commitment Period Conduct Test

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 an Internal Market Monitor-supported ~~first-year~~ break-even price for the Seasonal Capacity Auction

associated with the first Capacity Commitment Period of the deactivation 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~~ Internal Market Monitor's expected Capacity Clearing Price ~~submitted by the Lead Market Participant~~ for the Seasonal Capacity Auction associated with the first Capacity Commitment Period of the deactivation is more than 10% greater than the ~~first-year~~ Internal Market Monitor-supported 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 that Capacity Commitment Period.

III.A.24.5.2 Second Capacity Commitment Period Conduct Test

For those resources failing the conduct test associated with the first Capacity Commitment Period of the deactivation, the Internal Market Monitor shall also calculate an Internal Market Monitor-supported break-even price for the Seasonal Capacity Auction associated with the second Capacity Commitment Period of the deactivation 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. If the Internal Market Monitor's expected Capacity Clearing Price for the Seasonal Capacity Auction associated with the second Capacity Commitment Period of the deactivation is more than 10% greater than the Internal Market Monitor supported break-even price, then that resource fails the conduct test for that Capacity Commitment Period.

III.A.24.5.3 Conduct Test Outcomes

Resources that pass the conduct test associated with the first Capacity Commitment Period of the examined period shall deactivate consistent with the terms of their Deactivation Notification unless delaying deactivation pursuant to Section II.53. Notwithstanding the foregoing, the IMM may reconsider the outcome of a conduct test undertaken pursuant to this Section III.A.24.5 for a Capacity Commitment Period where a subsequent successive Deactivation Notification from the same resource impacting the same Capacity Commitment Period would alter the outcome of a conduct test undertaken during the preceding Capacity Commitment Period. For those Lead Market Participants with one or more resources failing the conduct test associated with the first Capacity Commitment Period of a deactivation, or both the first and second Capacity Commitment Period of a deactivation, the Internal Market Monitor shall perform a further review of the Lead Market Participant's portfolio pursuant to III.A.24.6 for each Capacity Commitment Period of conduct test failure.

III.A.24.6. Portfolio Benefit Test.

The portfolio benefit test is performed for each Lead Market Participant submitting a Deactivation Notification subject to further ~~Internal Market Monitor~~ review ~~that has failed the conduct test set forth in~~as a result of the outcomes described in Section III.A.24.5.3. The test will be performed as follows, for each Capacity Commitment Period of a conduct test failure, when that Capacity Commitment Period is within twelve months of commencing:

If

i. The ~~annual~~ seasonal capacity revenue from the Lead Market Participant's total ~~Annual Qualified Capacity~~Seasonal MRI Capacity, not including the ~~Annual Qualified Capacity~~ Seasonal MRI Capacity associated with the Lead Market Participant's Deactivation Notification(s), is greater than

ii. the ~~annual~~ seasonal capacity revenue from the Lead Market Participant's total Seasonal MRI Capacity~~Annual Qualified Capacity~~, not including the Seasonal MRI Capacity ~~Annual Qualified Capacity~~ associated with the Deactivation Notification(s) for resources controlled by the Lead Market Participant that ~~failed~~ passed the conduct test as calculated pursuant to subsection v. below, then

iii. the Lead Market Participant will be found to have a portfolio benefit in the relevant season pursuant to the portfolio benefit test.

Where,

iv. the Lead Market Participant's ~~annual~~ seasonal capacity revenue from the Lead Market Participant's total ~~Annual Qualified Capacity~~ Seasonal MRI Capacity not including the ~~Annual Qualified Capacity~~ Seasonal MRI Capacity associated with the Deactivation Notification(s) is calculated as the product of (a) the Lead Market Participant's total Seasonal MRI Capacity in the relevant season~~Annual Qualified Capacity~~ not including the ~~Annual Qualified Capacity~~Seasonal MRI Capacity associated with the Deactivation Notification(s) that ~~is~~ are the subject of the review and (b) the Internal Market Monitor-simulated Capacity Clearing Price not including the ~~Annual Qualified Capacity~~ Seasonal MRI Capacity associated with the Deactivation Notification(s).~~.~~

v. The Lead Market Participant's ~~annual~~ seasonal capacity revenue from the Lead Market Participant's total ~~Annual Qualified Capacity~~Seasonal MRI Capacity ~~-~~including the ~~Annual Qualified Capacity~~Seasonal MRI Capacity associated with the Deactivation Notification is calculated as the product of (a) the Lead Market Participant's total ~~Annual~~

~~Qualified Capacity~~Seasonal MRI Capacity in the relevant season not including the ~~Annual Qualified Capacity~~ Seasonal MRI Capacity associated with the Deactivation Notification(s) ~~that is the subject of the review~~that passed the conduct test and (b) the Internal Market Monitor-simulated Capacity Clearing Price including the ~~Annual Qualified Capacity~~ Seasonal MRI Capacity associated with the Deactivation Notification(s) that passed the conduct test.

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, external interface Capacity Transfer Limits ~~as specified in Section III.15.1~~, Gas-Constrained Winter Capacity Demand Curve, and the supply offers~~curve~~ developed from the most recent ~~Annual~~ like-season Seasonal Capacity Auction. Notwithstanding the foregoing, for the Capacity Commitment Periods beginning on June 1, 2028 and November 1, 2028, the Internal Market Monitor-simulated Capacity Clearing Price, not to exceed the Capacity Auction Offer Price Cap, shall be based on the System-Wide Capacity Demand Curve, Capacity Zone Demand Curves, external interface Capacity Transfer Limits, and the supply offers developed from the Forward Capacity Auction held on February 5, 2024.

For purposes of the test performed in this Section III.A.24, the ~~Annual Qualified Capacity~~ Seasonal MRI 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~~Seasonal MRI 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~~ failed the portfolio benefit test set forth in Section III.A.24.6 in either or both of

the first two Capacity Commitment Periods of the deactivation, then the Internal Market Monitor supported break-even price developed pursuant to Section III.A.24.5 shall be used as that resource's Proxy Capacity Offer price for the deactivating MRI Capacity for the Seasonal Capacity Auction(s) associated with the Capacity Commitment Period(s) failing the portfolio benefit test. Resources electing to delay deactivation pursuant to Section II.53 shall not be subject to a Proxy Capacity Offer during the Capacity Commitment Period(s) of delayed deactivation. ~~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 relevant Seasonal Capacity Auction pursuant to Section III.15.4.

III.A.24.8. Deactivation Determination Notification.

No later than 90 days after ~~the~~ each 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. In the event that the Internal Market Monitor reconsiders the outcome of a conduct test due to a subsequent successive Deactivation Notification, the Internal Market Monitor shall provide written notification to the Lead Market Participant of such reconsideration no later than 90 days after the Deactivation Notification Deadline associated with the successive Deactivation Notification.

III.A.24.9. Deactivation Determinations Filing.

No later than 120 days after ~~the~~ each 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 for the Capacity Commitment Period beginning one year after each Deactivation Notification Deadline, 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~~ Seasonal 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

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

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 or demonstrating capability 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 or demonstration 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 or demonstration.

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 or demonstrate capability, 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 or demonstration, 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 or demonstration is conduct

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 or demonstration of capability be performed that requires the ISO to dispatch the Resource for the audit or demonstration 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 or demonstration 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.

f. 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.

g. 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.

h. 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

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 Export Transaction through an import-constrained Reserve Zone that is not associated with a Capacity Supply Obligation~~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

I.2 Rules of Construction; Definitions

****

I.2.2. Definitions:

***

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

****

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

****

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

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

****

Asset is a Generator Asset, a Demand Response Asset, ~~a component of~~ an On-Peak Demand ~~Capacity Resource~~Asset, ~~or~~ a Seasonal Peak Demand ~~Capacity Resource~~Asset, a Distributed Generation Asset, a Load Management Asset, an Energy Efficiency Asset, ~~a Distributed Energy Resource participating as part of~~ a Demand Response Distributed Energy Resource Aggregation, the **s**ettlement **o**nly **c**omponent of a Demand Response Distributed Energy Resource Aggregation, a Settlement Only Distributed Energy Resource Aggregation, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

****

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

***

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

***

Capacity Commitment Period is the ~~one-year~~ period ~~from June 1 through May 31~~ for which obligations are assumed and payments are made in the ~~Forward~~ Capacity Market ~~and Annual Capacity Market.~~ For the Capacity Commitment Periods occurring prior to June 1, 2028, the Capacity Commitment Period is the one-year period from June 1 through May 31. For all Capacity Commitment Periods beginning on or after June 1, 2028, there shall be two seasonal Capacity Commitment Periods for which Capacity Supply Obligations are assumed and payments are made in the Capacity Market: a Summer Capacity Commitment Period and a Winter Capacity Commitment Period. For the Summer Capacity Commitment Period beginning on June 1, 2028, the Summer Capacity Commitment Period is the five-month period from June 1, 2028 through October 31, 2028. For all Capacity Commitment Periods thereafter, the Summer Capacity Commitment Period is the six-month period from May 1 through October 31 and the Winter Capacity Commitment Period is the six-month period from November 1 through April 30.

***

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

***

Capacity Import Capability is the transfer capability of an external interface determined pursuant to Section III.12.9.2.4.A.

***

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

***

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

***

Daily Maximum Usable Energy is defined in Section III.12.7.3.4(b).

***

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

***

Distributed Generation Asset is a type of Asset that is part of a Passive Demand Capacity Resource and that consists of Distributed Generation.

***

Energy-Limited Generating Capacity Resource is a type of Generating Capacity Resource described in Section III.15.3.1(a)(ii).

***

Energy Storage Generating Capacity Resource is a type of Generating Capacity Resource described in Section III.15.3.1(a)(iii).

***

Gas Availability Constraint is the constraint described in Section III.12.2.3.

Gas-Constrained Winter Capacity Demand Curve is the demand curve described in Section III.15.1.1.4.

***

Generating Capacity Resource Without Energy Limitations is a type of Generating Capacity Resource described in Section III.15.3.1(a)(i).

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process. Settlement Only Distributed Energy Resource Aggregation and the settlement only component of a Distributed Energy Resource Aggregation are Generator Assets.

***

Global Maximum Capability is the asset-specific capability value calculated by the ISO pursuant to Section III.1.5.4.

***

Hybrid Generating Capacity Resource is a type of Generating Capacity Resource described in Section III.15.3.1(a)(iv).

***

Initial Winter Parameters Study is the study that will produce the winter-relevant parameters needed to calculate the Seasonal Demand Anchor Price in accordance with Section III.15.1.1.5(a) for the Capacity Commitment Period beginning on June 1, 2028 (e.g. the system capacity Marginal Reliability Impact value at the system-wide Net Installed Capacity Requirement, Relative MRI, Maximum Capability, and Qualified Capacity values for all resources associated with the CONE technology type). The study shall be conducted, reviewed with stakeholders, and filed with the Commission in accordance with the process set forth in Section III.12.3.

***

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

***

Load Management Asset is a type of Asset that is part of a Passive Demand Capacity Resource and consists of Load Management.

***

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

***

Maximum Capability is the Global Maximum Capability of an Asset or Capacity Resource that is an Intermittent Power Resource, Seasonal Maximum Capability of an Asset or Capacity Resource that is not

an Intermittent Power Resource, Seasonal Maximum Capability equivalent of an Import Capacity Resource, and Seasonal Maximum Capability equivalent of a Passive Demand Capacity Resource composed of Energy Efficiency.

***

Maximum Capacity Limit for Gas-Constrained Winter Capacity is a value calculated as described in Section III.12.2.3 of Market Rule 1.

***

MRI Capacity is the amount, determined pursuant to Section III.15.3, that a Capacity Resource may qualify to offer in a Seasonal Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral. MRI Capacity shall be either Seasonal MRI Capacity or Monthly MRI Capacity.

***

Net Installed Capacity Requirement is defined in Section III.12.1,

***

New England Seasonal Class Average (NESCA) EFORd is defined in Section III.12.7.3.3(c).

***

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

***

Passive Demand Capacity Resource is a type of Demand Capacity Resource composed of either a Seasonal Peak Demand Capacity Resource, an On-Peak Demand Capacity Resource, Energy Efficiency Asset, Distributed Generation Asset, or Load Management Asset.

***

Perfect Capacity Resource is, for purposes of determining Relative MRI Values pursuant to Section III.12.1.2, a Capacity Resource that is available in every hour at its Maximum Capability and is fully deliverable to serve load and charge Electric Storage Facilities on the system.

***

Qualification Data Submission Package is the package submitted to the ISO by a Lead Market Participant seeking to qualify a resource for ~~the Annual~~ the Seasonal Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral pursuant to Section III.15.2.1.1.

***

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined prior to the 2028-2029 Capacity Commitment Period in the Forward Capacity Market qualification processes~~, or, for the 2028-2029 Capacity Commitment Period and all Capacity Commitment Periods thereafter, through the Annual Capacity Market qualification and demonstration processes~~.

***

Relative Marginal Reliability Impact (Relative MRI) is a value determined pursuant to Section III.12.1.2 comparing a resource-specific Marginal Reliability Impact value to the Marginal Reliability Impact value of a perfect Capacity Resource.

***

~~**Resource Adequacy Assessment Qualified Capacity** is the amount of summer and winter Qualified Capacity determined pursuant to Section III.15.3 of Market Rule 1 for all Capacity Resources identified in Section III.12.7.2(a) of Market Rule 1, at the start of the Resource Adequacy Assessment process that begins in June of the year preceding the relevant Capacity Commitment Period.~~

Resource Adequacy Assessment Consultation Deadline is the deadline described in Section III.12.7.3.5 for consultation regarding resource-specific Resource Adequacy Assessment inputs.

Resource Adequacy Assessment Input Deadline is the deadline described in Section III.12.7.3.5 for collection of resource-specific inputs used in the Resource Adequacy Assessment process.

***

Seasonal Capacity Auction is the Summer Capacity Auction or Winter Capacity Auction processes carried out pursuant to Section III.15.4 of Market Rule 1.

***

Seasonal Dependable Capability is the asset-specific capability value calculated by the ISO pursuant to Section III.1.5.6.

***

Seasonal EFORd is an input used in the resource adequacy assessment modeling process and described in Section III.12.7.3.3.

Seasonal Loss of Load Expectation (LOLE) Target is the resource adequacy planning criteria described in Section III.12.1(a).

Seasonal Maximum Capability is the asset-specific capability value calculated by the ISO pursuant to Section III.1.5.5.

***

Seasonal MRI Capacity may refer to the Seasonal MRI Capacity of a Capacity Resource or the Seasonal MRI Capacity of a Capacity Market parameter. The Seasonal MRI Capacity values of a Capacity Resource shall be the summer and winter Marginal Reliability Impact Capacity values determined pursuant to Section III.15.3. The Seasonal MRI Capacity of a Capacity Market parameter other than that which is assigned to a Capacity Resource pursuant to Section III.15.3 shall be the MRI equivalent of the value developed pursuant to Section III.12 or Section III.15.

***

Seasonal Qualified Inventory is defined in Section III.12.7.3.4(a).

***

Summer Capacity Auction is the Seasonal Capacity Auction through which Capacity Supply Obligations are assumed for the Summer Capacity Commitment Period.

Summer Capacity Commitment Period is one of two annually occurring Capacity Commitment Periods for which Capacity Supply Obligations are assumed and payments are made in the Seasonal Capacity Auction. The Summer Capacity Commitment Period is the six-month period from May 1 through October 31. Notwithstanding the foregoing, the first Summer Capacity Commitment Period for which Capacity Supply Obligations are assumed and payments are made in the Seasonal Capacity Auction shall be the five-month period from June 1, 2028 through October 31, 2028.

Summer Deliverability Scaling Factor is an input used in the resource adequacy assessment process and described in Section III.12.7.3.2.

***

Winter Capacity Commitment Period is one of two annually occurring Capacity Commitment Periods for which Capacity Supply Obligations are assumed and payments are made in the Seasonal Capacity Auction. The Winter Capacity Commitment Period is the six-month period from November 1 through April 30.

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III.12.9.5. Calculating Tie Benefits for Individual Ties.

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

III.12.9.6.1. [Reserved.] ~~Accounting for Capacity Imports~~.

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

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III.13 Forward Capacity Market.

III.13.1 Forward Capacity Auction Qualification.

III.13.1.1 New Generating Capacity Resources.

III.13.1.1.1 Definition of New Generating Capacity Resource.

III.13.1.1.1.1 Resources Never Previously Counted as Capacity.

III.13.1.1.1.2 Resources Previously Counted as Capacity.

(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 and Capability Values.

III.1.5.1 Claimed Capability Audits.

Claimed Capability Audits and Seasonal DR Audits as described in this section III.1.5.1 shall no longer occur after August 31, 2027.

III.1.5.1.1 General Audit Requirements.

(a) The following types of Claimed Capability Audits may be performed until August 31, 2027:

(i) An Establish Claimed Capability Audit establishes the Generator Asset's or Settlement Only Distributed Energy Resource Aggregation'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 or Settlement Only Distributed Energy Resource Aggregation'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) A Seasonal DRDERA Audit value determines the ability of a Demand Response Distributed Energy Resource Aggregation to perform during specified months for a specified duration.

(v) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Assets or Settlement Only Distributed Energy Resource Aggregation's Establish Claimed Capability Audit value, the Demand Response Resource's Seasonal DR Audit value or the Demand Response Distributed Energy Resource Aggregation's Seasonal DRDERA Audit value.

(b) The Claimed Capability Audit value of a Generator Asset or Settlement Only Distributed Energy Resource Aggregation 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 or Settlement Only Distributed Energy Resource Aggregation.

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

(c) For a newly commercial Generator Asset or Settlement Only Distributed Energy Resource Aggregation:

(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.1.5.4 Global Maximum Capability.

The Global Maximum Capability of a Generator Asset, Demand Response Asset, Distributed Generation Asset, or Load Management Asset, shall be determined as set forth in this Section III.1.5.4. The ISO shall begin determining Global Maximum Capability values pursuant to this Section III.1.5.4 on June 1, 2027.

(a) The Global Maximum Capability of an Asset shall be the Asset's maximum hourly demonstrated performance during the current month and preceding 36 calendar months, updated weekly.

(b) The ISO shall determine the Global Maximum Capability of a Generator Asset, Distributed Generation Asset, or Load Management Asset using submitted hourly revenue quality meter data, or the hourly average of five-minute revenue quality meter data.

(c) The ISO shall determine the Global Maximum Capability of Demand Response Assets using average hourly performance across twelve consecutive five-minute intervals, including both load reduction and incremental net supply, as measured in accordance with Section III.8.

(d) The Global Maximum Capability of aggregated resources shall be equal to the sum of the Global Maximum Capability of the Assets composing the aggregated resource.

(e) For the purposes of this Section III.1.5.4, a Capacity Resource that experiences a material change pursuant to Section III.15.2.4.1 shall be treated as if the performance history of the associated

Asset(s) undergoing the material change begins on the date described in the Qualification Data Submission Package submitted pursuant to III.15.2.4.1.

III.1.5.5 Seasonal Maximum Capability.

The Seasonal Maximum Capability of a Generator Asset, Demand Response Asset, Distributed Generation Asset, or Load Management Asset shall be the Asset's maximum hourly demonstrated performance during the current month and preceding 36 calendar months during seasonally-specific conditions, as defined in this Section III.1.5.5, updated weekly. The Seasonal Maximum Capability of an Asset shall not exceed the NR Capability (or equivalent) of that Asset for the corresponding season. The ISO shall determine the Seasonal Maximum Capability of aggregated resources using the sum of the relevant Seasonal Maximum Capability of the Assets composing the aggregated resource. For the purposes of this Section III.1.5.5, a Capacity Resource that has experienced a material change pursuant to Section III.15.2.4.1 shall be treated as if the performance history of the associated Asset(s) undergoing the material change begins on the date described in the Qualification Data Submission Package submitted pursuant to III.15.2.4.1. The ISO shall begin determining Seasonal Maximum Capability values pursuant to this Section III.1.5.5 on June 1, 2027.

III.1.5.5.1 Summer and Winter Seasonal Conditions.

(a) Summer Season Conditions:

(i) The ISO shall determine the summer Seasonal Maximum Capability of Generator Assets, Distributed Generation Assets, and Load Management Assets using submitted hourly revenue quality meter data or the hourly average of five-minute revenue quality meter data and the following hours: (a) hours when the system-average hourly temperature is greater than or equal to 80 degrees; (b) hours when the local hourly temperature is greater than or equal to 80 degrees where a Market Participant submits a post-dispatch notification to the ISO identifying the local temperature during the hour; and (c) hours occurring during a published capability demonstration window described in Section III.1.5.5.2. The summer Seasonal Maximum Capability value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to expected performance at 90 degrees; a Market Participant may request that the normalization reflect local temperatures during an hour by submitting a post-dispatch notification to the ISO identifying the local temperature during the hour. The post-dispatch notification of the local temperature during the hour must be submitted by 5:00 p.m. on the fifth Business Day following the day on which the hour occurred.

(ii) The ISO shall determine the summer Seasonal Maximum Capability of Demand Response Assets using average hourly performance data across twelve consecutive five-minute intervals, including both load reduction and incremental net supply, as measured in accordance with Section III.8, for hours occurring during the period between May 1 and October 31. A Market Participant seeking to demonstrate summer Seasonal Maximum Capability of a Demand Response Asset may request a dispatch of the associated Demand Response Resource, in which case the demonstration shall be performed at an unannounced time between 0800 and 2200 on a non-NERC holiday weekday within five Business Days of the date of the request. The demonstration shall be initiated by the ISO through issuance of a Dispatch Instruction ordering the Demand Response Resource to maintain its Maximum Reduction for twelve contiguous five-minute intervals, after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(b) Winter Season Conditions

(i) The ISO shall determine the winter Seasonal Maximum Capability of Generator Assets, Distributed Generation Assets, and Load Management Assets using submitted hourly revenue quality meter data or the hourly average of five-minute revenue quality meter data and the following hours: (a) hours when the system-average hourly temperature is less than our equal to 32 degrees; (b) hours when the local hourly temperature is less than or equal to 32 degrees where a Market Participant submits a post-dispatch notification to the ISO identifying the local temperature during the hour; and (c) during the published capability demonstration window described in Section III.1.5.5.2. The winter Seasonal Maximum Capability value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to expected performance at 20 degrees; a Market Participant may request that the normalization reflect local temperatures during an hour by submitting a post-dispatch notification to the ISO identifying the local temperature during the hour. The post-dispatch notification of the local temperature during the hour must be submitted by 5:00 p.m. on the fifth Business Day following the day on which the hour occurred.

(ii) The ISO shall determine the winter Seasonal Maximum Capability of Demand Response Assets using average hourly performance data across twelve consecutive five-minute intervals, including both load reduction and incremental net supply, as measured in accordance with Section III.8, for hours occurring during the period between November 1 and April 30. A Market Participant seeking to demonstrate the winter Seasonal

Maximum Capability of a Demand Response Asset may request a dispatch of the Demand Response Resource, in which case the demonstration shall be performed at an unannounced time between 0800 and 2200 on a non-NERC holiday weekday within five Business Days of the date of the request. The demonstration shall be initiated by the ISO through issuance of a Dispatch Instruction ordering the Asset to maintain its Maximum Reduction for twelve contiguous five-minute intervals, after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

III.1.5.5.2 Seasonal Maximum Capability Demonstration Window.

The ISO shall issue notice of a summer or winter Seasonal Maximum Capability demonstration window if the ISO determines that weather forecasts indicate that system-average temperatures during the demonstration window will meet the summer or winter Seasonal Maximum Capability temperature requirements described in Section III.1.5.5.1. A notice shall be issued at least 48 hours prior to the opening of the demonstration window. Any performance during the announced demonstration window shall be deemed to meet the temperature requirement for the summer or winter seasonal conditions described in Section III.1.5.5.1.

III.1.5.5.3 Seasonal Maximum Capability of Dual Fuel Assets.

The Seasonal Maximum Capability of an Asset capable of operating on more than one fuel shall be the Asset's maximum hourly demonstrated performance, using submitted hourly revenue quality meter data or the hourly average of five-minute revenue quality meter data during the current month and preceding 36 calendar months during seasonally-specific conditions set forth in Section III.1.5.5.1, except as provided herein. An Asset capable of operating on more than one fuel is assumed to be operating on its primary fuel unless the Market Participant communicates by post-dispatch notification to the ISO that the Asset was operating on its alternate fuel during an hour. The post-dispatch notification must be submitted by 5:00 p.m. on the fifth Business Day following the day on which the hour occurred. The Seasonal Maximum Capability of the Asset shall be calculated for both the primary and alternative fuel based on the hourly demonstrated performance, whether a post-dispatch notification of alternative fuel usage was submitted, and the alternate fuel MW output change value reported pursuant to ISO New England Operating Procedure No. 14, Appendix A.

III.1.5.5.4 Seasonal Maximum Capability of Newly Commercial Assets.

The Seasonal Maximum Capability of an Asset that has been operational for a period insufficient for the ISO to determine Seasonal Maximum Capability values according to observed performance during both the summer and winter conditions set forth in Section III.1.5.5.1 shall be determined as described in this Section III.1.5.5.4. For gas turbine, combined cycle, and pseudo-combined cycle Assets the maximum hourly performance shall be weather normalized to standard 90 degree summer and 20 degree winter temperatures; a Market Participant may request that the normalization reflect local temperatures during an hour by submitting a post-dispatch notification to the ISO identifying the local temperature during the hour by 5:00 p.m. on the fifth Business Day following the day on which the hour occurred. For all other Assets, the Seasonal Maximum Capability values of newly operational Assets shall be the greater of: (a) the demonstrated Seasonal Maximum Capability; or (b) based on a class-average ratio of Seasonal Maximum Capability to the Global Maximum Capability associated with the Asset's maximum hourly demonstrated performance. The Seasonal Maximum Capability set forth in this Section III.1.5.5.4 shall be valid only until the Asset has six complete calendar months of like-season performance.

III.1.5.6 Seasonal Dependable Capability

The Seasonal Dependable Capability of a Generator Asset, Demand Response Resource, Distributed Generation Asset, or Load Management Asset shall be determined based on the median availability of the Asset during the 100 highest load hours in the relevant season during the preceding twelve months as described in this Section III.1.5.6. The Seasonal Dependable Capability value of an Asset shall not exceed the Seasonal Maximum Capability value for the corresponding season. The Seasonal Dependable Capability of an aggregated resource shall be the sum of the Seasonal Dependable Capability of the Assets composing the aggregated resource. For the purposes of this Section III.1.5.6, a Capacity Resource that has experienced a material change pursuant to Section III.15.2.4.1 shall be treated as if the performance history of the associated Asset(s) undergoing the material change begins on the date described in the Qualification Data Submission Package submitted pursuant to III.15.2.4.1. The ISO shall begin determining Seasonal Dependable Capability values pursuant to this Section III.1.5.6 on June 1, 2027.

III.1.5.6.1. Seasonal Dependable Capability of DDP Dispatchable Resources.

The Seasonal Dependable Capability of an Asset or Demand Response Resource that is a DDP Dispatchable Resource shall be the median of the offered maximum (Economic Maximum Limit or Maximum Reduction) during the 100 highest load hours in the relevant season during the preceding twelve months, multiplied by a performance factor. The performance factor, updated weekly, shall be the sum of actual hourly performance (as measured by the minimum of the Desired Dispatch Point or actual

hourly performance) divided by the sum of hourly Desired Dispatch Point during all dispatch hours in the preceding twelve months. For purposes of this Section III.1.5.6.1, availability of a DDP Dispatchable Resource during an hour when the Asset or Demand Response Resource is off-line and not available for commitment shall be its hourly revenue quality meter data or the hourly average of five-minute revenue quality meter data for that hour.

III.1.5.6.2. Seasonal Dependable Capability of Resources Other Than DDP Dispatchable Resources.

The Seasonal Dependable Capability of an Asset that is not a DDP Dispatchable Resource, shall be the Asset's median performance, as calculated using hourly revenue quality meter data or the hourly average of five-minute revenue quality meter data, during the 100 highest load hours in the relevant season during the preceding twelve months.

III.1.5.6.3. Seasonal Dependable Capability of Newly Commercial Assets.

For those Assets that were not yet commercially available during any of the 100 highest load hours in the relevant season during the preceding 12 months, the Seasonal Dependable Capability shall be the Seasonal Maximum Capability multiplied by the class-average ratio of Seasonal Dependable Capability to Seasonal Maximum Capability. Until the Asset has six complete calendar months of like-season performance, the Seasonal Dependable Capability shall be the greater of: (a) the Asset's Seasonal Maximum Capability multiplied by the class-average ratio of Seasonal Dependable Capability to Seasonal Maximum Capability; or (b) the Asset's Seasonal Dependable Capability using only the hours occurring after the resource achieved commercial operation to determine its performance during the 100 highest load hours in the relevant season during the preceding twelve months.

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

III.12. Calculation of Capacity Requirements.

For the purposes of this Section III.12, a "resource" shall mean any resource that is or will be eligible to receive Capacity Base Payments in the Capacity Market during the relevant Capacity Commitment Period.

III.12.1. Installed Capacity Requirement.

Prior to each ~~Annual~~ Seasonal Capacity Auction, the ISO shall calculate the Installed Capacity Requirement for the New England Control Area for the Capacity Commitment Period associated with that ~~Annual~~ Seasonal Capacity Auction in accordance with this Section III.12.1. ~~Prior to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the ISO shall calculate an Installed Capacity Requirement for the New England Control Area for such Capacity Commitment Period in accordance with this Section III.12.1.~~

~~(a)~~ **Resource Adequacy Planning Criteria.**

(a)

The ISO shall determine the Installed Capacity Requirement, as further described in Section III.12.1(b), such that the probability of disconnecting non-interruptible customers due to resource deficiency, on average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be ~~no more than 0.1 day each year~~no more than the Seasonal LOLE Target of 0.05 days per Capacity Commitment Period.~~.~~ The forecast Installed Capacity Requirement shall meet this resource adequacy planning criterion for each Capacity Commitment Period. The Installed Capacity Requirement shall be determined assuming all resources pursuant to Sections III.12.7 and III.12.9 will be deliverable to meet the forecasted demand determined pursuant to Section III.12.8.

(b) **Installed Capacity Requirement.**

The Installed Capacity Requirement and Net Installed Capacity Requirement for each Capacity Commitment Period shall be determined in accordance with the following formulas:

$$\text{Installed Capacity Requirement} = \frac{Total\ Modeled\ Capacity}{1+\frac{ALCC}{Peak\ Load}} + HQICCs$$

Where:

Total Modeled Capacity	=	-Maximum Capability (MW) of the Capacity Resources described in Sections III.12.7.1 and III.12.7.2, except that the non-capacity supply described in Section III.12.7.4 (load and capacity relief) and Section III.12.9 (tie benefits) shall be excluded;
ALCC	=	The Additional Load Carrying Capability of the system as determined by the maximum feasible increase in peak load MW that yields a LOLE consistent with the criteria described in Section III.12.1(a), assuming a 50/50 peak load forecast developed pursuant to Section III.12.8 and taking into account the contribution from Capacity Resources described in Sections III.12.7.1 and III.12.7.2, as well as the non-capacity supply described in Section III.12.7.4 (load and capacity relief) and Section III.12.9 (tie benefits); and
Peak Load	=	The 50/50 peak load forecast MW developed pursuant to Section III.12.8.
HQICCs	=	The tie benefits calculated pursuant to Section III.15.1.4.
Net Installed Capacity Requirement	=	Installed Capacity Requirement - HQICCs

(c) **Review of Assumptions.**

If the Net Installed Capacity Requirement shows a consistent bias over time, either high or low, the ISO shall make adjustments to the modeling assumptions and/or methodology through the stakeholder process to eliminate the bias in the Net Installed Capacity Requirement. The modeling assumptions used in determining the Net Installed Capacity Requirement are specified in Sections III.12.7, III.12.8 and III.12.9. ~~For the purpose of this Section III.12, a "resource" shall mean any Capacity Resource eligible to receive Capacity Base Payments in the Annual or Forward Capacity Market.~~

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

Prior to each ~~Annual~~ Seasonal Capacity Auction, the ISO shall determine the system-wide Marginal Reliability Impact of incremental capacity at various capacity levels for the New England Control Area. The Marginal Reliability Impact value shall be determined using a probabilistic resource adequacy simulation program to calculate the impact on expected unserved energy from incremental system capacity supply to the unconstrained system. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used in determining the Net Installed Capacity Requirement. ~~Prior to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the ISO shall determine a system-wide Marginal Reliability Impact value for such Capacity Commitment Period.~~

III.12.1.2. Relative MRI Values

Prior to each Seasonal Capacity Auction, the ISO shall determine the Relative MRI values that will be used to determine the MRI Capacity for resources that participate in the Seasonal Capacity Auction. Section III.12.1.2 explains the Relative MRI determination process for each resource that is included in the resource adequacy assessment process for the Seasonal Capacity Auction pursuant to the modeling provisions in Section III.12.7.3. With the exception of Passive Demand Capacity Resources, Relative MRI values for resources that are not included in the resource adequacy assessment process are determined pursuant to Section III.15.3.2. Relative MRI values used in the determination of MRI Capacity values for Passive Demand Capacity Resources are determined pursuant to Section III.12.1.2.3.

The ISO shall publish representative Relative MRI values by resource type, derived from the resource types identified in Section III.15.3.1, prior to each Seasonal Capacity Auction as specified in the Capacity Auction Calendar.

III.12.1.2.1. Relative MRI Values for Resources Modeled in the Resource Adequacy Assessment Process.

Except as expressly identified in Section III.12.1.2.2, the Relative MRI for each resource included in the resource adequacy assessment process under Section III.12.7 shall be determined as follows:

(a) The ISO shall first calculate the MRI value for each resource included in the resource adequacy assessment process and for a Perfect Capacity Resource that is available in every hour at its Maximum Capability, using the methodologies set forth in Section III.12.1.2.2.

(b) The ISO shall then calculate the Relative MRI for each resource included in the resource adequacy assessment process by dividing the resource-specific MRI value by the MRI value of the Perfect Capacity Resource.

For purposes of these determinations, the ISO shall employ the same probabilistic resource adequacy modeling software that is used in determining the Installed Capacity Requirement, using the same inputs and assumptions regarding load, available resources and other system conditions that are employed for determining the Seasonal Capacity Auction's Installed Capacity Requirement.

III.12.1.2.2 Resource-Specific MRI Values.

The ISO shall calculate resource-specific MRI values for all Capacity Resources included in the resource adequacy assessment using the methodologies set forth in this Section III.12.1.2.2. These resource-specific MRI values shall be derived by representing resources included in the resource adequacy assessment as individual resources, an aggregated group of resources, or the underlying components of an individual resource, as specified in Section III.12.7.

The resource-specific MRI of the Perfect Capacity Resource shall be determined by increasing the resource's Seasonal Maximum Capability by a small MW amount and measuring the resulting change in the system's expected unserved energy. The Perfect Capacity Resource's MRI shall equal the change in the system's expected unserved energy per MW increase in Seasonal Maximum Capability.

(a) Generating Capacity Resources other than Intermittent Power Resources.

(i) **Generating Capacity Resource Without Energy Limitations**. The resource-specific MRI of a Generating Capacity Resource Without Energy Limitations shall be determined by increasing the resource's Seasonal Maximum Capability by a small MW amount and measuring the resulting change in the system's expected unserved energy. The resource's MRI shall equal the change in the system's expected unserved energy per MW increase in Seasonal Maximum Capability, and the resource's Relative MRI shall be calculated in accordance with Section III.12.1.2.1(b).

(ii) **Energy-Limited Generating Capacity Resources.** The resource-specific MRI of an Energy-Limited Generating Capacity Resource shall be determined by increasing the resource's, or if represented as part of an aggregation, the aggregation's Seasonal Maximum Capability by a small MW amount and the

resource's Daily Maximum Usable Energy by a proportional amount, and measuring the resulting change in the system's expected unserved energy. The resource's or aggregation's MRI shall equal the change in the system's expected unserved energy per MW increase in Seasonal Maximum Capability. For an individually represented resource, its Relative MRI shall be calculated in accordance with Section III.12.1.2.1(b). For a resource represented within an aggregation, its Relative MRI shall be the Relative MRI of the aggregation, which shall be calculated in accordance with Section III.12.1.2.1(b), adjusted to account for the individual resource's EFORd relative to the Seasonal Maximum Capability-weighted average EFORd of all the resources in the aggregation.

(iii) **Energy Storage Generating Capacity Resources.** The resource-specific MRI of an Energy Storage Generating Capacity Resource (whether represented individually or as an aggregation) shall be determined by increasing the resource's, or if represented as part of an aggregation, the aggregation's Seasonal Maximum Capability by a small MW amount, and increasing both the (1) maximum charging capability or pumping capability and (2) maximum storage capacity by a proportional amount, and measuring the resulting change in the system's expected unserved energy. The resource's or aggregation's MRI shall equal the change in the system's expected unserved energy per MW increase in Seasonal Maximum Capability. For an individually represented resource, its Relative MRI shall be calculated in accordance with Section III.12.1.2.1(b). For a resource represented within an aggregation, its Relative MRI shall be the Relative MRI of the aggregation, which shall be calculated in accordance with Section III.12.1.2.1(b), adjusted to account for the individual resource's EFORd relative to the Seasonal Maximum Capability-weighted average EFORd of all the resources in the aggregation.

(iv) **Hybrid Generating Capacity Resources.** The resource-specific MRI of Hybrid Generating Capacity Resources shall be determined at the facility level using the characteristics of each technology component of the facility and the facility limit. A facility-level MRI shall be calculated by adding to the model a small hypothetical facility, represented by a small MW increase in the facility limit, with that facility containing the same technology components, and the same ratio of those components, as the target facility for which the MRI is being calculated. The MRI of the facility shall be equal to the change in the system's expected unserved energy per MW increase in the facility limit. The resource's Relative MRI shall be the Relative MRI of the facility calculated in accordance with Section III.12.1.2.1(b).

(b) Intermittent Power Generating Capacity Resources. The resource-specific MRI of an Intermittent Power Generating Capacity Resource (whether represented individually or as an aggregation) shall be determined by increasing the resource's, or if represented as part of an aggregation, the

aggregation's Global Maximum Capability by a small MW amount, and measuring the resulting change in the system's expected unserved energy. The resource's MRI shall equal the change in the system's expected unserved energy per MW increase in Global Maximum Capability. For an individually represented resource, its Relative MRI shall be calculated in accordance with Section III.12.1.2.1(b). For a resource represented within an aggregation, its Relative MRI shall be the Relative MRI of the aggregation, which shall be calculated in accordance with Section III.12.1.2.1(b).

(c) Active Demand Capacity Resources.

The resource-specific MRI of an Active Demand Capacity Resource shall be determined by increasing the resource's Seasonal Maximum Capability by a small MW amount, and measuring the resulting change in the system's expected unserved energy. The resource's MRI shall equal the change in the system's expected unserved energy per MW increase in Seasonal Maximum Capability, and the resource's Relative MRI shall be calculated in accordance with Section III.12.1.2.1(b).

(d) Distributed Energy Capacity Resources.

The resource-specific MRI of a Distributed Energy Capacity Resource shall be determined by increasing the resource's Seasonal Maximum Capability by a small MW amount, and measuring the resulting change in the system's expected unserved energy. The resource's MRI shall equal the change in the system's expected unserved energy per MW increase in Seasonal Maximum Capability, and the resource's Relative MRI shall be calculated in accordance with Section III.12.1.2.1(b).

III.12.1.2.3 Relative MRI Values Related to Passive Demand Capacity Resources.

The ISO shall calculate Relative MRI values for use in the determination of MRI Capacity values for Passive Demand Capacity Resources using the methodologies set forth in this Section III.12.1.2.3. The determination of MRI Capacity values for Passive Demand Capacity Resources is set forth in Section III.15.3.2(d).

(a) **Energy Efficiency.** The ISO shall derive Relative MRI values for use in the determination of MRI Capacity values for Passive Demand Capacity Resources that consist of Energy Efficiency by modeling the various Energy Efficiency residential-sector and commercial-sector end uses that are included in Passive Demand Capacity Resources throughout the New England Control area and determining the Relative MRI values for each sector and end-use combination. The MRI for each sector and end-use combination shall be calculated by adding to the resource adequacy assessment model a

small hypothetical resource representing such combination and measuring the resulting change in the system's expected unserved energy. The small hypothetical resource shall be modeled using normalized hourly profiles that reflect the expected hourly, system-wide demand reduction for the sector and end-use combination it represents. The MRI for each modeled sector and end-use combination shall equal the change in the system's expected unserved energy, per MW addition of the small hypothetical resource to the model. The Relative MRI value for each modeled sector and end-use combination shall be determined by dividing the hypothetical resource MRI value by the MRI value of the Perfect Capacity Resource.

(b) **Distributed Generation and Load Management.** The ISO shall derive Relative MRI values for use in the determination of MRI Capacity values for Passive Demand Capacity Resources that consist of Distributed Generation or Load Management by modeling groups of Distributed Generation Assets and Load Management Assets, determined by technology type, that are included in Passive Demand Capacity Resources throughout the New England Control Area and determining the Relative MRI values for every group of assets within a Passive Demand Capacity Resource as follows:

(i) The MRI for each technology type shall be calculated by adding to the resource adequacy assessment model a small hypothetical resource representing all system-wide Distributed Generation Assets and Load Management Assets of such technology type and measuring the resulting change in the system's expected unserved energy. The small hypothetical resource shall be modeled using normalized hourly profiles that reflect the expected hourly, system-wide output for the technology type it represents. For the hypothetical resource representative of photovoltaic solar technology, the normalized hourly profile will reflect the correlation between such assets' output and system load and be determined using the weighted average of a normalized hourly profile determined for each load zone. The MRI for each modeled technology type shall equal the change in the system's expected unserved energy, per MW addition of the small hypothetical resource to the model. The Relative MRI value for each technology type shall be determined by dividing the hypothetical resource MRI value by the MRI value of the Perfect Capacity Resource.

(ii) For each group of assets of the same technology type that is within a single Passive Demand Capacity Resource and has a combined Seasonal Maximum Capability equal to or greater than 5 MW, the Relative MRI for such group of assets shall be the Relative MRI for the group's technology type determined in paragraph (i), adjusted to reflect the ratio of the group's combined Seasonal Dependable Capability to the group's combined Seasonal

Maximum Capability, relative to the ratio of the combined Seasonal Dependable Capability to combined Seasonal Maximum Capability for all system-wide Distributed Generation Assets and Load Management Assets of the same technology type.

(iii) For each group of assets of the same technology type that is within a single Passive Demand Capacity Resource and has a combined Seasonal Maximum Capability less than 5 MW, the Relative MRI for such group of assets shall be the Relative MRI for the group's technology type determined in paragraph (i), adjusted to reflect the ratio of the combined Seasonal Dependable Capability to the combined Seasonal Maximum Capability for all system-wide Distributed Generation Assets and Load Management Assets of the same technology type that have a Seasonal Maximum Capability less than 5 MW, relative to the ratio of the combined Seasonal Dependable Capability to the combined Seasonal Maximum Capability for all system-wide Distributed Generation Assets and Load Management Assets of the same technology type, independent of size.

III.12.2. ~~Local Sourcing Requirements and,~~ Maximum Capacity Limits, Gas Availability Constraint, and Capacity Import Capability.

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

The ISO shall use consistent assumptions and standards ~~to establish a resource's electrical location~~ for purposes of qualifying a resource for the ~~Annual~~ Capacity Market and for purposes of calculating Local Sourcing Requirements, ~~and~~ Maximum Capacity Limits, and the Gas Availability Constraint. The methodology used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.2.1 ~~and,~~ III.12.2.2, and III.12.2.3.2~~respectively~~. The methodology used in determining the Gas Availability Constraint is specified in Section III.12.2.1. The modeling assumptions used in determining the Local Sourcing Requirements, ~~and~~ the Maximum Capacity Limits, and Gas Availability Constraint are specified in Sections III.12.5, III.12.6, III.12.7, III.12.8 and III.12.9.

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

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

III.12.2.1.1. Local Resource Adequacy Requirement.

The Local Resource Adequacy Requirement shall be calculated as follows:

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

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

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

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

~~LRA$_Z$ = $\frac{Resources - \frac{FLA}{rMRI}}{1 + ALCC\ \%}$ Resources$_z$ + Proxy Units$_z$ – (Proxy Units Adjustment$_z$(1-FOR$_z$)) (Firm Load Adjustment$_z$(1-FOR$_z$))~~

In which:

LRA_Z = MW of Local Resource Adequacy Requirement for Capacity Zone Z;

$Resources_{Z}$ = Maximum Capability (MW) of resources electrically located within Capacity Zone Z, including Iimport Capacity Resources on the import-constrained side of the interface, as well as any proxy units, if any;

~~$Proxy\ Units_z$ = MW of proxy unit additions in Load Zone Z;~~

Firm Load Adjustment (FLA)$_{Z}$ = MW of firm load added (or subtracted) within Capacity Zone Z to make the LOLE of the New England Control Area equal to the Seasonal LOLE Target, plus an allowance for transmission-related LOLE equal to 5% of the Seasonal LOLE Target;~~0.105 2days per year; and~~

~~FOR_z~~$rMRI_Z$ = Capacity weighted Relative MRI ~~average of the forced outage rate modeled for~~of all resources within Capacity Zone Z, including any proxy unit additions to Capacity Zone Z~~.~~; and

~~Proxy Units~~ Adjustment$ALCC\%$ = The additional load carrying capability of the system divided by

the 50/50 peak load of the system as described in ~~in~~ Section III.12.1(b).~~MW of firm load added to (or unforced capacity subtracted from) Capacity Zone Z until the system LOLE equals 0.1 days/year.~~

To determine the Local Resource Adequacy Requirement, the firm load is adjusted within Capacity Zone Z until the LOLE of the New England Control Area reaches ~~0.105 2days per year~~the Seasonal LOLE Target, plus an allowance for transmission-related LOLE equal to 5% of the Seasonal LOLE Target. ~~The LOLE of 0.105 2days per year includes an allowance for transmission related LOLE of 0.0025 days per year associated with each interface.~~ As firm load is added to (or subtracted from) Capacity Zone Z, an equal amount of firm load is removed from (or added to) the rest of New England Control Area.

III.12.2.1.2. Transmission Security Analysis Requirement.

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

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

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

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

(d) The Transmission Security Analysis may model the entire New England system and individual zones, for both the first contingency (N-1) and second contingency (N-1-1) conditions. First contingency

conditions (N-1) shall include the loss of the most critical generator or most critical transmission element with respect to the zone. Second contingency conditions (N-1-1) shall include both: (i) the loss of the most critical generator with respect to the zone followed by the loss of the most critical transmission element ("Line-Gen"); and (ii) the loss of the most critical transmission element followed by the loss of the next most critical transmission element ("Line-Line") with respect to the zone.

III.12.2.1.3. Marginal Reliability Impact Values for Import-Constrained Capacity Zones.

Prior to each Seasonal ~~Annual~~ Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each import-constrained Capacity Zone. The Marginal Reliability Impact value shall be determined using a probabilistic resource adequacy simulation program to calculate the impact on expected unserved energy from replacing an increment of capacity supply in the Rest-of-Pool Capacity Zone with an increment of capacity supply in the import-constrained Capacity Zone while maintaining a total system capacity quantity equal to the Net Installed Capacity Requirement. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the Local Resource Adequacy Requirement pursuant to Section III.12.2.1.1, except that the zonal demand curve developed using the unadjusted interface limit shall be shifted horizontally to the right by an amount equal to the difference between the Transmission Security Analysis Requirement and Local Resource Adequacy Requirement~~the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area determined pursuant to Section III.12.2.1.1(b) shall be reduced by the greater of: (i) the Transmission Security Analysis Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero~~.

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

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

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

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

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

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

$$MCL_Z = \frac{Resources - \frac{FLA}{rMRI}}{1 + ALCC\ \%}$$

Where:

MCL_Z = Maximum Capacity Limit (MW) for Capacity Zone Z

$Resources_Z$ = Maximum Capability (MW) of resources electrically located within Capacity Zone Z, including Import Capacity Resources on the export-constrained side of the interface, as well as any proxy units, if any;

Firm Load Adjustment $(FLA)_Z$ = MW of firm load added (or subtracted) within Capacity Zone Z to make the LOLE of the New England Control Area equal to the Seasonal LOLE Target, plus an allowance for transmission-related LOLE equal to 5% of the Seasonal LOLE Target;

$rMRI_Z$ = Capacity weighted relative Marginal Reliability Impact of all resources within Capacity Zone Z, including any proxy unit additions to Capacity Zone Z; and

ALCC% = The additional load carrying capability of the system divided by the 50/50 peak load of the system as described in Section III.12.1(b). ~~Capacity Zone Y shall be determined in accordance with the following formula:~~

~~$\text{Maximum Capacity Limit}_Y = \text{ICR} - \text{LRA}_{\text{RestofNewEngland}}$~~

~~In which:~~

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

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

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

To determine the Maximum Capacity Limit, the firm load is adjusted within Capacity Zone Z until the LOLE of the New England Control Area reaches the Seasonal LOLE Target, plus an allowance for transmission-related LOLE equal to 5% of the Seasonal LOLE Target. As firm load is added to (or subtracted from) Capacity Zone Z, an equal amount of firm load is removed from (or added to) the rest of New England Control Area.

III.12.2.2.1. Marginal Reliability Impact Values for Export-Constrained Capacity Zones.

Prior to each ~~Annual~~ Seasonal Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each export-constrained Capacity Zone. The Marginal Reliability Impact value shall be determined using a probabilistic resource adequacy simulation program to calculate the impact on expected unserved energy from replacing an increment of capacity supply in the Rest-of-Pool Capacity Zone with an increment of capacity supply in the export-constrained Capacity Zone while maintaining a total system capacity quantity equal to the Net Installed Capacity

Requirement. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's Maximum Capacity Limit. ~~Prior to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the ISO shall determine zonal Marginal Reliability Impact values for each export-constrained Capacity Zone for such Capacity Commitment Period.~~

III.12.2.3. Calculation of Maximum Capacity Limit for Gas-Constrained Winter Capacity.
For each Winter Capacity Auction, the ISO shall calculate the Maximum Capacity Limit for Gas-Constrained Winter Capacity pursuant to Section III.12.2.3.2 based on the Gas Availability Constraint developed pursuant to Section III.12.2.3.1.

III.12.2.3.1 Calculation of the Gas Availability Constraint.
Prior to each Winter Capacity Auction, the ISO shall determine the Gas Availability Constraint pursuant to this Section III.12.2.3.1 for use as an input to calculate the Marginal Reliability Impact value of gas-constrained winter capacity pursuant to Section III.12.2.3.3. ISO shall determine the Gas Availability Constraint by simulating the quantity of gas available for power generation during the Gas Firming Period through the development of a set of probability-weighted gas availability profiles for each of the modeled load years, with each of the profiles reflecting a different gas availability metric (i.e., from smallest availability to largest availability). Each of the probability-weighted profiles shall be calculated as a function of available gas on the two consecutive days of lowest gas availability for the year, where availability is a function of (a) pipeline gas supply as measured on high gas inflow days for the existing pipeline gas delivery system in New England, (b) liquified natural gas supply as measured using an econometric model of liquified natural gas supply that accounts for weather variability, liquified natural gas injection variability, and the impacts of non-weather-related variables such as day-to-day (weekday, weekend, holiday) and month-to-month differences, and (c) non-generator gas demand as measured using an econometric model of non-generator gas demand that measures gas demand as a function of historical pipeline flows and receipt/delivery of gas, weather variability, and the impacts of non-weather-related variables.

For the Seasonal Capacity Auction associated with the Capacity Commitment Period beginning on November 1, 2028, the modeled load years shall include the 23 winter seasons occurring between November 2000 and April 2023 and the set of probability-weighted gas availability profiles shall consist

of ten profiles. Any modification of the modeled load years for subsequent Capacity Commitment Periods shall be described in the filing made pursuant to Section III.12.3.

III.12.2.3.2 Maximum Capacity Limit for Gas-Constrained Winter Capacity.

The Maximum Capacity Limit for the Gas-Constrained Winter Capacity shall be calculated using the following method:

(a) Two areas shall be modeled: (i) a proxy export-constrained zone which includes all the gas-only resources in the New England Control Area without load; and (ii) the rest of the New England Control Area, which includes all load and all other non-gas-only resources in the New England Control Area, including external Control Area support from tie benefits to the rest of the New England Control Area, if any.

(b) The only transmission constraint to be modeled shall be a proxy transmission interface limit between the proxy export-constrained zone and the rest of the New England Control Area. The proxy interface limit shall be based on the Gas Availability Constraint as determined pursuant to Section III.12.2.3.1.

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE absent the transmission constraint is less than the Seasonal LOLE Target, the load shall be scaled so that the unconstrained system LOLE equals the Seasonal LOLE Target.

(d) The Maximum Capacity Limit for the gas-constrained winter capacity shall be determined in accordance with the following formula:

$$MCL_G = \frac{Resources - \frac{FLA}{rMRI}}{1 + ALCC\ \%}$$

Where:

MCL_G = Maximum Capacity Limit (MW) for the gas-constrained winter capacity

$Resources_G$ = Maximum Capability (MW) of gas-only resources modeled

within the proxy export-constrained zone, as well as any proxy units, if any;

Firm Load Adjustment (FLA)$_G$	=	MW of firm load added (or subtracted) within the proxy export-constrained zone to make the LOLE of the New England Control Area equal to the Seasonal LOLE Target plus an allowance for transmission-related LOLE equal to 5% of the Seasonal LOLE Target;
$rMRI_G$	=	Capacity weighted relative Marginal Reliability Impact of all gas-only resources within the proxy export-constrained zone, including any proxy unit additions to zone; and
ALCC%	=	The additional load carrying capability of the system divided by the 50/50 peak load of the system as described in Section III.12.1(b).

To determine the Maximum Capacity Limit, the firm load is adjusted within the proxy export-constrained zone until the LOLE of the New England Control Area reaches the Seasonal LOLE Target plus an allowance for transmission-related LOLE equal to 5% of the Seasonal LOLE Target. As firm load is added to (or subtracted from) the proxy export-constrained zone, an equal amount of firm load is removed from (or added to) the rest of New England Control Area.

III.12.2.3.3 Marginal Reliability Impact Value of Gas-Constrained Winter Capacity

Prior to each Winter Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for gas-constrained winter capacity subject to the Gas Availability Constraint. The Marginal Reliability Impact value shall be determined using the Gas Availability Constraint established pursuant Section III.12.2.3 and a probabilistic resource adequacy simulation program to calculate the impact on expected unserved energy from replacing an increment of non-gas resource capacity supply in the rest of pool with an increment of gas resource capacity supply while maintaining a total system capacity quantity equal to the Net Installed Capacity Requirement.

III.12.2.4. External Interface Capacity Import Capability.

The interface-specific MRI of an external interface's Capacity Import Capability shall be determined by increasing its seasonal Capacity Import Capability by a small MW amount and measuring the resulting change in the system's expected unserved energy. The MRI shall equal the change in the system's expected unserved energy resulting from the increase in the seasonal Capacity Import Capability. The MRI calculated for such an interface represents the reliability impact of the equivalent thermal resource and shall not be deemed the MRI of Import Capacity Resources associated with that interface.

III.12.3 Consultation and Filing of Capacity Requirements.

(a) **Capacity Requirements Filing.** At least two months prior to filing the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for the relevant Capacity Commitment Period with the Commission, the ISO shall review the modeling assumptions and resulting Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves, the Gas-Constrained Winter Capacity Demand Curve, as relevant, and aggregated capacity accreditation results with the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. Following consultation with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO shall file the modeling assumptions and resulting Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve, ~~and~~ Capacity Zone Demand Curves, the Gas-Constrained Winter Capacity Demand Curve, as relevant, and aggregated capacity accreditation results for the Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act at least 90 days prior to ~~the Annual~~ each Seasonal Capacity Auction for the relevant Capacity Commitment Period. ~~For the capacity requirements that the ISO will determine for the Capacity Commitment Period beginning on June 1, 2027 described in Sections III.12.1 and III.12.2, the ISO shall file such Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves with the Commission pursuant to Section 205 of the Federal Power Act at least 90 days prior to the third annual reconfiguration auction for such Capacity Commitment Period.~~

(b) **New Capacity Zone Filing.** The ISO shall file with the Commission pursuant to Section 205 of the Federal Power Act, the proposed identification of a potential new Capacity Zone when

the boundary of the potential new Capacity Zone differs from the boundaries of existing Load Zones or Capacity Zones. In order to be used in a given ~~Annual~~ Seasonal Capacity Auction, any new Capacity Zone must be accepted by the Commission prior to the Deactivation Notification Deadline of the applicable ~~Annual~~ Seasonal Capacity Auction.

III.12.4. Capacity Zones.

For each Seasonal~~Annual~~ Capacity Auction, the ISO shall, using the results of the most recent annual assessment of transmission transfer capability conducted pursuant to ISO Tariff Section II, Attachment K, determine the Capacity Zones to model as described below, and will publish the Capacity Zones modeled for the ~~Annual~~ Seasonal Capacity Auction publicly on its website prior to conducting the auction, in accordance with Section III.15.9:

(a) The ISO shall model in the ~~Annual~~ Seasonal Capacity Auction, as separate export-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the Maximum Capacity Limit in the preceding like-season is less than the sum of~~:~~ : (1) estimated Seasonal MRI Capacity of all Capacity Resources in the zone that have established summer CNR Capability or equivalent CNR Capability, qualified to participate in the Capacity Market pursuant to Section III.15.2, demonstrated performance pursuant to Section III.15.2.6, and have not submitted a Deactivation Notification for the relevant Capacity Commitment Period,~~the Resource Adequacy Assessment Qualified Capacity and~~ (2) the nameplate value (or equivalent) of resources in the zone that have established summer CNR Capability or equivalent CNR Capability and are expected to achieve Capacity Market Commercial Operation prior to the relevant Capacity Commitment Period~~potential new capacity that could qualify to be procured in the export constrained Capacity Zone~~, and (3) ~~including~~ an assumed import capacity value~~potential Import Capacity Resources on the export-constrained side of the interface~~,~~.~~ for each external interface connected to the zone, equal to the difference between the external interface's Capacity Import Capability and the tie benefits associated with the interface, as determined pursuant to Section III.12.9.

(b) The ISO shall model in the ~~Annual~~ Seasonal Capacity Auction, as separate import-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the second contingency transmission capability results in a line-line Transmission Security Analysis Requirement in the relevant season, calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, that is greater than ~~the~~ Seasonal Dependable Capability of all Capacity Resources ~~Resource~~

~~Adequacy Assessment Qualified Capacity~~ in the Capacity ~~z~~Zone that have established summer CNR Capability or equivalent CNR Capability, qualified to participate in the Capacity Market pursuant to Section III.15.2, and demonstrated performance pursuant to Section III.15.2.6,~~-~~ with the following modeled as out-of-service: (1) all capacity for which a Deactivation Notification has been submitted for the relevant Capacity Commitment Period, (2) the largest remaining generating station in the Capacity Z~~z~~one ~~modeled as out-of-service~~, and (3) for the Winter Capacity Commitment Period only, 75% of the remaining Seasonal Dependable Capability of gas-only Capacity Resources. ~~Each assessment will model out-of-service all capacity for which a Deactivation Notification has been submitted for the relevant Capacity Commitment Period.~~

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

III.12.4A. Dispatch Zones.

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

III.12.5. Transmission Interface Transfer Capabilities~~Limits~~.

Transmission interface transfer capabilities~~limits~~, used in the Capacity Zone modeling process, the determination of tie benefits,~~determination of~~ the determination of Maximum Capacity Limits, and the determination of Local Sourcing Requirements, shall be determined pursuant to ISO Tariff Section II, Attachment K using the network model conditions described in Section III.12.6 and Section III.12.9.2.4.A~~s that include all resources, existing transmission lines and proposed transmission lines that the ISO determines, in accordance with Section III.12.6, will be in service no later than the first day of the relevant Capacity Commitment Period~~. The transmission interface ~~limits~~ transfer capabilities shall be established, using deterministic analyses, at levels that provide acceptable thermal, voltage and stability performance of the system both with all lines in service and after any criteria contingency occurs as specified in ISO New England Manuals and ISO New England Administrative Procedures.

III.12.6. Capacity Market Network Modeling Assumptions ~~for Determining the Network Model~~.

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

~~(a)~~ For the relevant Capacity Commitment Period, ~~the~~athe Capacity Market network modeling assumptions shall include:

(~~a~~i) all ~~existing~~ Capacity ~~r~~Resources that have demonstrated performance pursuant to Section III.15.2.6 and are not planned for retirement or deactivation during the Capacity Commitment Period~~,~~;

(b) resources that have established CNR Capability or equivalent CNR Capability and have an expected Commercial Operation Date before the start of the applicable Capacity Commitment Period but have not yet qualified ~~as a Capacity Resource~~for participation in the Capacity Market pursuant to Section III.15.2 and demonstrated performance pursuant to Section III.15.2.6~~, along with any associated interconnection facilities and/or Elective Transmission Upgrades that have not been approved to be retired for the relevant Capacity Commitment Period, as described in Sections III.13.2.5.2.5.3 and III.13.2.8.3 for the Forward Capacity Market, and other than those for which a Deactivation Notification has been submitted for the Annual Capacity Market~~; and

(~~ii~~c) In-service transmission elements not planned for retirement or deactivation during the Capacity Commitment Period, and planned transmission elements listed in the RSP Project List, Asset Condition List, and in any Local System Plan and with an in-service date prior to the start of the Capacity Commitment Period, or that the ISO has reason to believe will be in-service prior to the Capacity Commitment Period. The ISO shall model as out-of-service: (1) those transmission elements it has reason to believe will not be in-service prior to start of the Capacity Commitment Period, regardless of in-

service date; and (2) those External Elective Transmission Upgrades that have not established CNI Capability.

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

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

~~(b) Prior to each Annual~~ Seasonal ~~Capacity Auction, the ISO shall determine and publish a list of the transmission projects and elements of transmission projects that will be included in the network model. During the process of making the transmission infrastructure determinations, as described in Section III.12.6.1, the ISO shall consult with the Governance Participants, the Transmission Owners, any transmission project proponents, the state utility regulatory agencies in New England and, as appropriate, other state agencies. Prior to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the ISO shall determine and publish a list of the transmission projects and elements of transmission projects that will be included in the network model for such third annual reconfiguration auction.~~

~~**III.12.6.1. Process for Establishing the Network Model.**~~

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

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

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

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

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

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

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

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

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

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

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

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

~~III.12.6.3. Evaluation Criteria~~~~.~~

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

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

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

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

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

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

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

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

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

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

III.12.7. Resource Modeling Assumptions.

III.12.7.1. Proxy Units.

When the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion specified in Section III.12.1, proxy units shall be used as additional capacity to determine the Net Installed Capacity Requirement, Local Resource Adequacy

Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. The proxy units shall reflect resource capacity and outage characteristics, as described in the Installed Capacity Requirement Technical Guide or successor documentation~~,such that when the proxy units are used in place of all other resources in the New England Control Area, the reliability, or LOLE, of the New England Control Area does not change~~. ~~The outage characteristics are the summer capacity weighted average availability of the resources in the New England Control Area as determined in accordance with Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Control Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.~~

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

III.12.7.2. Capacity Modeled.

(a) For calculations made in relation to the Capacity Commitment Period beginning on June 1, 2028 and Capacity Commitment Periods thereafter, the resources included in the calculation of the Net Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, and Marginal Reliability Impact values, unless otherwise specified pursuant to this Section III.12, shall exclude Capacity Resources for which a Deactivation Notification has been submitted that will be in effect for the relevant Capacity Commitment Period, Passive Demand Capacity Resources, and Import Capacity Resources~~-~~, and shall include: (1) all Capacity Resources that have established summer CNR Capability or equivalent CNR Capability, qualified to participate in the Capacity Market pursuant to Section III.15.2, and demonstrated performance pursuant to Section III.15.2.6 prior to the Resource Adequacy Assessment Input Deadline identified in the Capacity Auction Calendar; and (2) an assumed import capacity value at a level equal to the difference between each external interface's Capacity Import Capability and the tie benefits associated with the interface, as determined pursuant to Section III.12.9~~that cleared in any previous Annual Capacity Auction or Forward Capacity Auction but shall exclude (i) Import Capacity Resources that are not backed by a multiyear contract to provide capacity in the New England Control Area that requires delivery of capacity for the Capacity Commitment Period for which the calculations are made and (ii) capacity from Capacity Resources for which a Deactivation Notification has been submitted that will be in effect for the relevant Capacity Commitment Period~~.

~~The rating of Capacity Resources used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be the Resource Adequacy Assessment Qualified Capacity for the upcoming Capacity Commitment Period. Resources are located within the Capacity Zones in which they are electrically connected as determined during the Resource Adequacy Assessment Qualified Capacity process.~~

~~(b) For calculations made in relation to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the resources included in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall include:~~

~~(i) all Existing Generating Capacity Resources,~~

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

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

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

~~but shall exclude:~~

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

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

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

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

III.12.7.3. ~~Resource Availability~~ Modeling Resources for Resource Adequacy Assessments.

For purposes of performing the resource adequacy assessments specified in this Section III.12, the ISO shall represent resources in the model in accordance with this Section III.12.7.3 using the resource technology categorizations specified in Section III.15.3.1. Section III.12.7.3.1 specifies the primary modeling features and inputs by technology type. Section III.12.7.3.2 explains the application of the Summer Deliverability Scaling Factor in the modeling of resources. Section III.12.7.3.3 explains the determination of resource EFORd values for use in resource adequacy assessments. Section III.12.7.3.4 describes the calculation of Seasonal Qualified Inventory values and Daily Maximum Usable Energy. Section III.12.7.3.5 describes the resource adequacy assessment consultation process.

III.12.7.3.1. Resource Modeling by Technology Type.

(a) Generating Capacity Resources other than Intermittent Power Resources.

(i) **Generating Capacity Resources Without Energy Limitations.** Generating Capacity Resources Without Energy Limitations shall be modeled using their Seasonal Maximum Capability and accounting for their EFORd.

(ii) **Energy-Limited Generating Capacity Resources.** Energy-Limited Generating Capacity Resources shall be modeled using their Seasonal Maximum Capability, accounting for their EFORd, and subject to their Daily Maximum Usable Energy.

Oil-only Capacity Resources or dual-fuel Capacity Resources that share a common oil storage shall be modeled together to reflect the impact of the common storage capacity.

Dual-fuel Capacity Resources shall be modeled at the greater of their oil-based and gas-based Seasonal Maximum Capability.

(iii) **Energy Storage Generating Capacity Resources.** Energy Storage Generating Capacity Resources shall be modeled using their Seasonal Maximum Capability, maximum storage capacity, round-trip efficiency, and maximum charging capability or pumping capability, and reflecting the impacts of resource outages. Resources that share a common storage shall be modeled together to reflect the impact of the common storage.

(iv) **Hybrid Generating Capacity Resources.** Hybrid Generating Capacity Resources shall be modeled by including each component technology comprising the resource in accordance with the modeling requirements for the applicable technology type as set forth in this Section III.12.7.3, except that all energy storage components within a Load Zone shall be modeled in an aggregation that reflects the characteristics of the underlying energy storage components. Hybrid Generating Capacity Resources shall not be modeled with a facility limit.

(b) Intermittent Power Generating Capacity Resources. Intermittent Power Generating Capacity Resources shall be modeled using their Global Maximum Capability and normalized hourly profiles that reflect the expected hourly output and the impacts of resource outages. Where the output of Intermittent Power Generating Capacity Resources exhibits correlations with system load or with other resources of the same type, such correlations shall be reflected in the modeling of those resources.

Intermittent Power Generating Capacity Resources shall be modeled together using an aggregated representation when available data on individual resources are insufficient to adequately represent a resource's performance, or when size of resources, number of resources, or other similar factors render individual modeling impractical and an aggregation would adequately represent the performance characteristics of the individual resources. Aggregations shall group resources based on technology type,

geographic location, and other characteristics that result in the aggregated resources exhibiting performance attributes that are similar to the resources that comprise the aggregation.

(c) Demand Capacity Resources.

(i) **Active Demand Capacity Resources**. Active Demand Capacity Resources shall be modeled using their Seasonal Maximum Capability (adjusted for transmission and distribution losses) and normalized hourly profiles that reflect the expected hourly resource availability. Normalized hourly profiles shall be developed based on the Maximum Reduction offer of the Active Demand Capacity Resource's Demand Response Resource(s) during the ten non-holiday weekdays and five weekend-days and holidays with the highest system load within the three most recent like-seasons. The Maximum Reduction offer shall be adjusted by a performance factor and, once adjusted, shall not exceed the Seasonal Maximum Capability of the resource at the time of the Maximum Reduction offer. The performance factor shall be based on the total demand reduction and Net Supply provided by the Demand Response Resource divided by the Desired Dispatch Point of the Demand Response Resource during the relevant interval. For those Demand Response Resources with performance data insufficient to determine hourly profiles, the ISO shall use participant-level profile data, scaled by the ratio of the participant's aggregate Seasonal Maximum Capability to the Demand Response Resource's Seasonal Maximum Capability. If the Lead Market Participant of these Demand Response Resources does not have other Demand Response Resources with which to calculate the participant-level profile, the Demand Response Resources shall receive a profile based on representative values derived from the Active Demand Capacity Resources in the New England Control Area.

(ii) **Passive Demand Capacity Resources.** Passive Demand Capacity Resources shall not be modeled in the resource adequacy assessment processes in this Section III.12.

(d) Distributed Energy Capacity Resources. Distributed Energy Capacity Resources shall be modeled using their Seasonal Maximum Capability (with any Demand Response Resource or Demand Response Distributed Energy Resource Aggregation component adjusted for transmission and distribution losses) and normalized hourly profiles that reflect the expected hourly resource availability.

(e) Import Capacity Resources and External Interfaces. Import Capacity Resources shall not be directly modeled in the resource adequacy assessment process. Each external interface with New

England shall be represented as a supply resource to capture the combined resource adequacy contribution of import capacity resources and any tie benefits associated with that interface. Each such external interface shall be modeled as an equivalent thermal resource, without energy limitations, at a Seasonal Maximum Capability equal to the interface's seasonal Capacity Import Capability and a forced outage rate based on the interface's historical unavailability rating.

III.12.7.3.2. Application of the Summer Deliverability Scaling Factor.

In modeling resources for the Summer Capacity Auction, a Summer Deliverability Scaling Factor shall apply to the Seasonal Maximum Capability of all Capacity Resources other than Passive Demand Capacity Resources and Import Capacity Resources.

The Summer Deliverability Scaling Factor shall be applied to a resource by multiplying the Seasonal Maximum Capability of the resource by the lesser of:

(i) the ratio of the resource's summer CNR Capability or equivalent as described in Section II.48.5.2 to the median of the resource's Seasonal Dependable Capability from the three most recent summer seasons; and

(ii) one.

For Hybrid Capacity Resources, the Summer Deliverability Scaling Factor shall be applied to the facility and then allocated to the individual components of the facility as specified by the Market Participant. For resources that do not have Seasonal Dependable Capability values from the three most recent summers, the ISO shall estimate the resource's median Seasonal Dependable Capability for purposes of calculating the Summer Deliverability Scaling Factor, until such time as there is adequate data to calculate the median value using the method contemplated in (i) above.

III.12.7.3.3. Seasonal EFORd.

For purposes of modeling resources in the resource adequacy assessment processes, Seasonal EFORd shall be calculated as follows:

(a) A resource's Seasonal EFORd shall be calculated using the GADS Data submitted by Market Participants for each unit within the resource weighted by capacity, as specified in the ISO New England Manuals and Planning Procedures. This data shall include summer or winter EFORd GADS Data from the Seasonal EFORd lookback period described in Section III.12.7.3.3(d).

(b) At the time of the determination of the Seasonal EFORd, if the necessary data to calculate Seasonal EFORd for any of the resource's units are not available for any month in the Seasonal EFORd lookback period described in Section III.12.7.3.3(d), the ISO shall determine a Seasonal EFORd that is an average of the resource's reported outage and derate data and the NESCA EFORd value, weighted based on the number of reported months relative to unreported months.

(c) For the purpose of this Section III.12.7.3.3, a New England Seasonal Class Average NESCA EFORd is a weighted average, within a season, of all of the Seasonal EFORd values calculated for resources within a technology type grouping using their reported data, including outage and derate data, for the entirety of the past ten seasons.

(d) For the resource adequacy assessment associated with the Capacity Commitment Period beginning June 1, 2028, the Capacity Commitment Period beginning June 1, 2031, and every sixth Capacity Commitment Period thereafter, the Lead Market Participant associated with a Capacity Resource may, by the date specified in the Capacity Auction Calendar, elect a Seasonal EFORd lookback period, for that Capacity Resource, of: (a) the ten most recent like-seasons (60 like-season months); or (b) the three most recent like-seasons (18 like-season months). An election made pursuant to this Section III.12.7.3.3(d), or the default lookback period applied in the case that no election is made, shall apply to all summer and winter Seasonal EFORd lookback periods until a new election is made. For those Capacity Resources that make no election pursuant to this Section III.12.7.3.3(d) during the resource adequacy assessment consultation period associated with the Capacity Commitment Period beginning on June 1, 2028, the ISO shall determine the Capacity Resource's Seasonal EFORd using a lookback period of the ten most recent like-seasons. For those resources that have never previously participated as capacity, the Lead Market Participant shall elect the Seasonal EFORd lookback period described herein within the Qualification Data Submission Package described in Section III.15.2.1.1. Notwithstanding the foregoing, the Seasonal EFORd lookback period of a resource-backed Import Capacity Resource shall be the three most recent like-seasons (18 like-season months).

III.12.7.3.4. Seasonal Qualified Inventories and Daily Maximum Usable Energy.

For purposes of modeling resources in the resource adequacy assessment processes of this Section III.12, Seasonal Qualified Inventory values and Daily Maximum Usable Energy values shall be calculated in accordance with this Section III.12.7.3.4.

(a) Seasonal Qualified Inventory. A resource's Seasonal Qualified Inventory shall represent the MWh that the resource can provide before fuel replenishment, and shall be calculated as a function of the average of the median fuel inventory levels of the resource from the prior three like-seasons (summer or winter), as reflected in the results of the ISO fuel surveys conducted in accordance with ISO New England Operating Procedures, and the resource's heat rate. For resources that do not have three like-seasons of fuel survey data, the Seasonal Qualified Inventory shall be calculated using the resource's available fuel survey data, including fuel survey data collected during resource commercial operation testing and data from the opposite season where in-season data is not available. Where no fuel survey data is available, the Seasonal Qualified Inventory shall be calculated as a function of the resource's maximum fuel inventory capacity. For those instances where fuel survey data includes data collected during a period when the resource was on outage or its fuel inventory capacity was reduced, the Lead Market Participant may request that the ISO omit fuel survey data from that period in the calculation of a Seasonal Qualified Inventory value in accordance with the consultation provisions set forth in Section III.12.7.3.5.

(b) Daily Maximum Usable Energy. A resource's Daily Maximum Usable Energy represents the maximum amount of electricity it can produce in a single day, and shall be equal to the resource's Seasonal Qualified Inventory. For purposes of resource adequacy assessment modeling, a resource that reaches its Daily Maximum Usable Energy shall have its available capacity set to zero MW for the remainder of the day.

III.12.7.3.5. Resource Adequacy Assessment Consultation Period

Following each Resource Adequacy Assessment Input Deadline identified in the Capacity Auction Calendar, the ISO shall notify each Lead Market Participant associated with a Capacity Resource that has demonstrated performance pursuant to Section III.15.2.6 of the resource-specific modeling assumptions that shall be used to determine the Relative MRI of its Capacity Resource. If the Lead Market Participant believes that its (1) Seasonal Qualified Inventory value or (2) Demand Response Resource Maximum Reduction offer do not accurately reflect the historically observed capability of the resource, or otherwise warrant alteration, it may request consultation by the relevant Resource Adequacy Assessment Consultation Deadline identified in the Capacity Auction Calendar. The ISO, after due consideration and consultation with the Lead Market Participant, shall notify the Lead Market Participant of the outcome of any request submitted by the date specified in the Capacity Auction Calendar for such responses.

~~(a) For calculations made in relation to the Capacity Commitment Period beginning on June 1, 2028, and Capacity Commitment Periods thereafter, the Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated taking resource availability into account and shall be determined as follows:~~

~~For Generating Capacity Resources, the most recent five-year moving average of EFORd shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. For Generating Capacity Resources that do not have sufficient data to calculate an availability metric using the most recent five-year moving average of EFORd, class average data for similar resource types shall be used.~~

~~For Active Demand Capacity Resources, historical performance data for those resources shall be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.~~

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

~~(b) For calculations made in relation to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated taking resource availability into account and shall be determined as follows:~~

~~(i) For Existing Generating Capacity Resources:~~

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

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

~~(iii) For existing Active Demand Capacity Resources:~~
~~historical performance data for those resources will be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.~~

III.12.7.4. Load and Capacity Relief.

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

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

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

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

III.12.8. Load Modeling Assumptions.

The ISO shall forecast load during the relevant Capacity Commitment Period for the New England Control Area and for each Load Zone within the New England Control Area pursuant to this Section III.12.8. Load modeling shall be based on the data inputs and modeling described in Section III.12.8.1, as

further detailed in the capacity requirements filing made pursuant to Section III.12.3. The load forecast shall be reviewed annually as described in Section III.12.8.2. Demand Response Resources shall be considered in the load forecast as described in III.12.8.3.

III.12.8.1. Load Modeling Inputs.

~~The l~~Load ~~forecasts~~ modeling applicable to this Section III.12 shall be based on ~~appropriate models and data inputs~~ the hourly net load forecast data used to develop the ISO's Capacity, Energy, Load, and Transmission Report and described in the filing made pursuant to Section III.12.3. If only a subset of the hourly net load forecast can be ~~explicitly~~directly modeled due to the need to adequately capture correlations between resource output profiles and the system demand profile, the ISO shall assign appropriate weights to the modeled hourly net load forecast to reasonably represent the full hourly net load forecast to achieve a similar level of resource adequacy.

III.12.8.2. Annual Review of Load Forecast.

Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall, through its annual load forecast review stakeholder process, propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias.

III.12.8.3. Load Forecast Adjustment for Demand Response Resources.

To ensure that Demand Response Resources~~, On-Peak Demand Capacity Resources, and Seasonal Peak Demand Capacity Resources~~ are not reflected as reductions in the load forecast, the ISO shall ~~reflect them in historical loads as specified below.~~

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

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

~~The ISO shall develop a trend line between (i) the point when summer MW values for On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources are assumed to be zero (June 1,~~

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

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

~~As necessary prior to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the ISO shall make adjustments to forecasted loads to account for any differences between the most recently available MW values reflective of the Capacity Supply Obligations that On-Peak Demand Capacity Resources and Seasonal Peak Demand Capacity Resources acquired in each of the annual reconfiguration auctions and the MW values reflective of the Capacity Supply Obligations that those resources acquired in the corresponding Forward Capacity Auctions.~~

III.12.9. Tie Benefits.

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

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

III.12.9.1. Overview of Tie Benefits Calculation Procedure.

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

For ~~each~~the Capacity Commitment Period beginning June 1, 2028, and all Capacity Commitment Periods thereafter, tie benefits shall be calculated for each Summer Capacity Commitment Period and the immediately subsequent Winter Capacity Commitment Period, contemporaneously, on a triennial basis~~for the Annual Capacity Auction~~ using the calculation methodology in this Section III.12.9. For those interim year Summer and Winter Capacity Commitment Periods that are not the subject of the triennial tie benefits calculation, the ISO shall determine whether a change in Capacity Import Capability on one or more external interface(s) requires an update of the tie benefit value associated with that external interface. If the ISO determines that tie benefit values shall be updated, the updated tie benefit values shall be used for the remainder of the triennial period unless modified as a result of a subsequent interim year analysis. The ISO shall describe the results of the triennial tie benefits calculation and any interim updates in the Installed Capacity Requirements filing made pursuant to Section III.12.3. ~~Prior to the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the ISO shall calculate tie benefits for such Capacity Commitment Period using the calculation methodology in this Section III.12.9.~~

Tie benefits shall be calculated using the modeling assumptions developed in accordance with Section III.12.9.2 and using a probabilistic resource adequacy simulation program.

III.12.9.1.2. Tie Benefits Calculation.

The total tie benefits to New England from all directly interconnected neighboring Control Areas are calculated first using the methodology in Section III.12.9.3. Following the calculation of total tie benefits, individual tie benefits from each qualifying neighboring Control Area are calculated using the methodology in Section III.12.9.4.1. If the sum of the tie benefits from each Control Area does not equal

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

~~**III.12.9.1.3. Adjustments to Account for Transmission Import Capability and Capacity Imports.** Once the initial calculation of tie benefits is performed, the tie benefits for each individual interconnection or group of interconnections is adjusted to account for capacity imports and any changes in the import capability of interconnections with neighboring Control Areas, using the methodologies in Section III.12.9.6. Once the import capability and capacity import adjustments are completed, the sum of the tie benefits of all individual interconnections and groups of interconnections for a Control Area, with the import capability and capacity import adjustments, represents the tie benefits associated with that Control Area, and the sum of the tie benefits from all Control Areas, with the import capability and capacity import adjustments, represents the total tie benefits available to New England.~~

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

In filing the capacity requirement values pursuant to Section III.12.3, the ISO shall provide citations to any resource adequacy studies relied upon to evaluate the resource adequacy requirements in the neighboring Control Areas and any adjustments the ISO has made to the modeling assumptions contained within those studies.

III.12.9.2.1. Assumptions Regarding System Conditions.

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

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

In calculating tie benefits, all New England internal transmission constraints that (i) are modeled in the most recent Regional System Plan resource adequacy studies and assessments and (ii) are not addressed

by either a Local Sourcing Requirement or a Maximum Capacity Limit calculation shall be modeled, using the procedures in Section III.12.9.2.5.

III.12.9.2.3. Modeling Transmission Constraints in Neighboring Control Areas.

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

III.12.9.2.4. ~~Other Modeling Assumptions~~Capacity Import Capability.

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

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

~~———~~1. The forecast 90/10 peak load conditions for the Capacity Commitment Period;

2. ~~Qualified~~ Generating Capacity Resources reflecting their ~~output at their Capacity Network Resource level~~CNR Capability;

3. ~~Qualified~~ Demand Capacity Resources reflecting their equivalent CNR Capability~~Capacity Supply Obligation received in the most recent Forward Capacity Auction or Annual Capacity Auction, as appropriate~~;

4. ~~Qualified~~ Distributed Energy Capacity Resources reflecting their ~~existing Qualified~~equivalent CNR Capability ~~Capacity~~ for the Capacity Commitment Period;

5. Resources that have established CNR Capability or equivalent CNR Capability and have an expected Commercial Operation Date before the start of the applicable Capacity Commitment Period; and

~~5~~6. Transfers on the transmission system that impact the transfer capability of the interconnection under study.

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

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

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

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

In calculating tie benefits, capacity shall be added or removed from the interconnected system of New England and its neighboring Control Areas, until the LOLE of the New England Control Area equals the Seasonal LOLE Target, the New York Control Area equals 0.05 days per Capacity Commitment Period and the LOLE of the Quebec and Maritimes Control Areas ~~each Control Area of the interconnected system~~ equal~~s~~ 0.1 days per year, simultaneously. The following procedures shall be used to add or remove capacity within New England and the interconnected Control Areas to achieve that goal.

A. Adding Proxy Units within New England when the New England system is short of capacity. In modeling New England as part of the interconnected system, if New England is short of capacity to meet the ~~0.1 days per year LOLE~~Seasonal LOLE Target, proxy units (with the characteristics identified in Section III.12.7.1) will be added to the sub-areas that are created by any modeled internal transmission constraints within New England, beginning

with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the New England Control Area, then proxy units will be added to the entire Control Area. If, as a result of the addition of one or more proxy units, the system is surplus of capacity, then the methodology in Section III.12.9.2.5.~~(b~~B~~)~~ will be used to remove the surplus capacity.

B. Removing capacity from New England when the New England system is surplus of capacity. In modeling New England as part of the interconnected system, if New England is surplus of capacity to meet the ~~0.1 days per year LOLE~~Seasonal LOLE Target, the surplus capacity will be removed from the sub-areas until the New England Control Area has reached the Seasonal LOLE Target, beginning with the lowest LOLE sub-area.~~as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in these surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the Resource Adequacy Assessment Qualified Capacity, and any amount of proxy units added in that sub-area that is above its 50-50 peak load forecast. For the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, the amount of capacity surplus for a sub-area is the amount of the existing Qualified Capacity.~~ Notwithstanding the foregoing, if removing resources will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas beginning with the lowest LOLE sub-area~~using the same ratios described above for the removal of capacity surplus~~. If there are no modeled internal transmission constraints in the New England Control Area, then the surplus capacity shall be removed from the entire Control Area.

C. Adding capacity within neighboring Control Areas when the neighboring Control Area is short of capacity. In modeling neighboring Control Areas as part of the interconnected system, if the ~~neighboring~~New York Control Area is short of capacity to meet the 0.05 days per Capacity Commitment Period LOLE, the Quebec Control Area is short of capacity to meet the 0.1 days per year LOLE, or the Maritimes Control Area is short of capacity to meet the 0.1 days per year LOLE, additional capacity will be added to the ~~neighboring~~ relevant Control Area's sub-areas that are created by any modeled internal transmissions constraints, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the Control Area, then capacity will be added to the entire Control Area.~~ The process that the neighboring Control Area utilizes in its resource adequacy study to meet its resource adequacy criterion will be utilized to add capacity to that Control Area.~~

~~In filing the Installed Capacity Requirement values pursuant to Section III.12.3, the ISO will provide citations to any resource adequacy studies relied upon for these purposes.~~ If, as a result of the capacity addition, the system is surplus of capacity, then the methodology in Section III.12.9.2.5.~~(d~~D~~)~~ shall be used to remove the surplus capacity.

D. Removing capacity from neighboring Control Areas when the neighboring Control Area is surplus of capacity. In modeling neighboring Control Areas as part of the interconnected system, if the ~~neighboring~~ New York Control Area is surplus of capacity to meet the 0.05 days per Capacity Commitment Period LOLE, the Quebec Control Area is surplus of capacity to meet the 0.1 days per year LOLE, or the Maritimes Control Area is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the ~~neighboring~~ relevant Control Area's sub-areas as follows. Resources will be removed from sub-areas with capacity surplus until the neighboring Control Area has reached the relevant LOLE value, beginning with the lowest LOLE sub-area~~based on the ratio of capacity surplus in the sub-area to the total capacity surplus in the surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the installed capacity in the sub-area above its 50/50 peak load forecast. For a sub-area that has a minimum locational resource requirement above its 50/50 peak load forecast, the amount of capacity surplus is the amount of the installed capacity in the sub-area above its minimum locational resource requirement.~~ Notwithstanding the foregoing, if removing resources from a sub-area will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas beginning with the lowest LOLE sub-area~~using the same ratio of capacity surplus in the sub-area to the total capacity surplus in the those remaining surplus sub-areas~~. If there are no modeled internal transmission constraints in the neighboring Control Area, then the surplus capacity will be removed from the entire Control Area.

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

III.12.9.3. Calculating Total Tie Benefits.

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

neighboring Control Areas connected with the interconnection state of the New England system with all interconnections with neighboring Control Areas disconnected. To calculate total tie benefits:

A. The New England system shall be modeled as interconnected with all directly interconnected neighboring Control Areas. ~~and t~~The New England Control Area shall be brought to the Seasonal LOLE Target, the New York Control Area shall be brought to 0.05 days per Capacity Commitment Period LOLE, the Quebec Control Area shall be brought to 0.1 days per year LOLE, and ~~each neighboring~~the Maritimes Control Area shall be brought to 0.1 days per year LOLE simultaneously by adjusting the capacity of each Control Area, utilizing the methods for adding or removing capacity in Section III.12.9.2.5.

B. Once the interconnected system is brought to ~~0.1 days per year~~the LOLE described in III.12.9.3.A, the LOLE of the New England Control Area shall be calculated a second time, with the New England system isolated from the rest of the interconnected system that was brought to ~~0.1 days per year~~ the LOLE described in III.12.9.3.A.

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

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

III.12.9.4.1. ~~Initial~~ Calculation of a Control Area's Tie Benefits.

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

III.12.9.4.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual Control Area tie benefits calculated in accordance with Section III.12.9.4.1 is different than the total tie benefits from all Control Areas calculated in accordance with Section III.12.9.3,

then each Control Area's tie benefits shall be increased or decreased based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits for each individual Control Area, so that the sum of each Control Area's tie benefits, after the pro-ration, is equal to the total tie benefits calculated in accordance with Section III.12.9.3. ~~The pro-rated Control Area tie benefits are subject to further adjustment in accordance with Section III.12.9.6.~~

III.12.9.5. Calculating Tie Benefits for Individual Ties.

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

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

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

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

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

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

Control Area calculated in accordance with Section III.12.9.4. ~~The pro-rated tie benefits for each interconnection or group of interconnections is subject to further adjustment in accordance with Section III.12.9.6.~~

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

III.12.9.6.1. [Reserved.] ~~Accounting for Capacity Imports.~~

~~In the initial tie benefits calculations, capacity imports are modeled as internal resources in New England, and the import capability of the interconnections with neighboring Control Areas is not reduced to reflect the impact of capacity imports. After the initial tie benefits calculations, total tie benefits, tie benefits for each Control Area, and tie benefits from each individual interconnection or group of interconnections shall be adjusted to account for capacity imports using the methodology contained in this Section III.12.9.6.1. For each Annual Capacity Auction and the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, this adjustment shall be applied to the tie benefit values calculated in accordance with Sections III.12.9.3, III.12.9.4 and III.12.9.5 respectively.~~

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

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

~~The tie benefits for each Control Area shall be the sum of the tie benefits from the individual interconnections or groups of interconnections with that Control Area, after accounting for any~~

~~adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.~~

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

~~For purposes of determining the adjustment to tie benefits to account for capacity imports under this Section III.12.9.6.1, the capacity imports applicable for determining tie benefits for the Annual Capacity Auction shall be any Import Capacity Resources previously cleared in a Forward Capacity Auction or Annual Capacity Auction backed by a multiyear contract to provide capacity in the New England Control Area, where that multiyear contract requires delivery of capacity for the relevant Capacity Commitment Period. The capacity imports applicable for determining tie benefits for the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, are those Import Capacity Resources that hold Capacity Supply Obligations for the relevant Capacity Commitment Period as of the time the tie benefits calculation is being performed for such annual reconfiguration auction.~~

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

For purposes of calculating tie benefits for each ~~Annual~~ Seasonal Capacity Auction ~~and the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027,~~ the most recent Capacity ~~import~~ Import ~~capability~~ Capability values for an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the modeling of system conditions for the tie benefits calculation.

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

The tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF calculated in accordance with Section III.12.9.1, as adjusted pursuant to Section III.15.3, shall be used for determining the HQICC allocated to the Interconnection Rights Holders or their designees in proportion to their respective percentage shares of the HQ Phase I and the HQ Phase II facilities, in accordance with Section I of the Transmission, Markets and Services Tariff.

~~**III.12.10. Calculating the Maximum Amount of Import Capacity Resources that May be Cleared Over External Interfaces in the Annual Capacity Auction.**~~

~~For external interfaces, Import Capacity Resources shall be allowed in the Annual Capacity Auction and the third annual reconfiguration auction conducted pursuant to Section III.13.4.2.1.2.2 for the Capacity Commitment Period beginning on June 1, 2027, up to the interface limit minus the tie benefits, calculated pursuant to Section III.12.9.1 or 12.9.2 over the applicable interface.~~

I.2 Rules of Construction; Definitions

***

I.2.2. Definitions:

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

***

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

***

Asset is a Generator Asset, a Demand Response Asset, ~~a component of~~ an On-Peak Demand ~~Capacity Resource~~Asset, ~~or~~ a Seasonal Peak Demand ~~Capacity Resource~~Asset, a Distributed Generation Asset, a Load Management Asset, an Energy Efficiency Asset, ~~a Distributed Energy Resource participating as part of~~ a Demand Response Distributed Energy Resource Aggregation, the **s**ettlement **o**nly **c**omponent of a Demand Response Distributed Energy Resource Aggregation, a Settlement Only Distributed Energy Resource Aggregation, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

***

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

Capacity Commitment Period is the ~~one-year~~ period ~~from June 1 through May 31~~ for which obligations are assumed and payments are made in the ~~Forward~~ Capacity Market ~~and Annual Capacity Market.~~ For the Capacity Commitment Periods occurring prior to June 1, 2028, the Capacity Commitment Period is the one-year period from June 1 through May 31. For all Capacity Commitment Periods beginning on or after June 1, 2028, there shall be two seasonal Capacity Commitment Periods for which Capacity Supply Obligations are assumed and payments are made in the Capacity Market: a Summer Capacity Commitment Period and a Winter Capacity Commitment Period. For the Summer Capacity Commitment Period beginning on June 1, 2028, the Summer Capacity Commitment Period is the five-month period

from June 1, 2028 through October 31, 2028. For all Capacity Commitment Periods thereafter, the Summer Capacity Commitment Period is the six-month period from May 1 through October 31 and the Winter Capacity Commitment Period is the six-month period from November 1 through April 30.

***

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

***

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

***

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

***

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

***

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

***

Proxy Capacity Offer is a type of offer used in the ~~Annual~~ Capacity Market.

***

Qualification Data Submission Deadline is a date specified in the Capacity Auction Calendar by which a Lead Market Participant seeking to have a resource participate in ~~the Annual~~ the Seasonal Capacity Auction must submit qualification materials pursuant to Section III.15.2.1.1.

***

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined prior to the 2028-2029 Capacity Commitment Period in the Forward Capacity Market qualification processes~~, or, for the 2028-2029 Capacity Commitment Period and all Capacity Commitment Periods thereafter, through the Annual Capacity Market qualification and demonstration processes~~.

***

Rationing Minimum Limit is the MW quantity below which a Capacity Offer may not be rationed in the ~~Annual~~ Seasonal Capacity Auction.

***

~~**Transition Period**: The six-year period commencing on March 1, 1997.~~

***

II.48 Interconnection Service Capabilities

II.48.1 Establishing CNR Capability and CNI Capability

(a) CNR Capability shall be established as follows: Section 5.2.3 of Schedule 22 and Section 5.2.3 of Schedule 23 of this OATT describe the establishment of CNR Capability for a Generating Facility that was treated as an Existing Generating Capacity Resource in the fourth Forward Capacity Auction. For a Generating Facility newly obtaining or increasing CNR Interconnection Service in the fourth Forward Capacity Auction through Forward Capacity Market activities prior to September 4, 2025, summer CNR Capability shall be established as the highest MW quantity of Capacity Supply Obligation obtained by the Generating Capacity Resource for the summer period and winter CNR Capability shall be established as the higher of (1) the highest MW quantity of Capacity Supply Obligation obtained by the associated Generating Capacity Resource for the winter period and (2) the Generating Facility's summer CNR Capability multiplied by the ratio of the Generating Capacity Resource's winter Qualified Capacity to summer Qualified Capacity for the auction in which the entry occurred. Commencing September 4, 2025, the summer and winter CNR Capability for a Generating Facility shall be established as the amounts requested in the Generating Facility's Interconnection Request, for which all of the requirements in the Interconnection Procedures have been completed, and which shall not exceed the maximum net MW electrical output at the Point of Interconnection at an ambient temperature at or above 90 degrees F for summer and at or above 20 degrees F for winter.

Notwithstanding the requirements contained in this section, a Generating Facility that did not secure a Capacity Supply Obligation prior to September 4, 2025, may establish CNR Interconnection Service through the process described in Section III.13.A.2 - Interim Reconfiguration Auction Qualification, conducted between January 1, 2025 and January 1, 2026, provided that the Generating Facility (1) has a completed System Impact Study or Interconnection Agreement establishing NR Interconnection Service on or before April 4, 2025 and (2) has a Commercial Operation Date prior to June 1, 2028.

CNI Capability shall be established as follows: Summer and winter CNI Capability for an External ETU with CNI Interconnection Service pursuant to Schedule 25 of this OATT shall be established as the amounts requested in the External ETU's Interconnection Request for which all of the requirements of the interconnection process have been completed.

Notwithstanding the requirements contained in this section, an External ETU that did not secure a Capacity Supply Obligation prior to September 4, 2025, may establish CNI Interconnection Service through the process described in Section III.13.A.2 - Interim Reconfiguration Auction Qualification, conducted between January 1, 2025 and January 1, 2026, provided that the External ETU (1) has a completed System Impact Study or Interconnection Agreement establishing NI Interconnection Service on or before April 4, 2025.

At the time of its establishment pursuant to the preceding paragraph, the CNI Capability shall not exceed the maximum net MW electrical capability at the Point of Interconnection and shall not exceed applicable seasonal equipment ratings determined pursuant to industry standards and consistent with the specifications described in ISO New England Planning and Operating Procedures.

II.48.2 Establishing NR Capability and NI Capability

(a) NR Capability shall be established in the manner described in Schedules 22 and 23 of this OATT. Summer and winter NR Capability for a Generating Facility shall be established as the Generating Facility's maximum net MW electrical output at the Point of Interconnection at an ambient temperature at or above 50 degrees F for summer and at or above 0 degrees F for winter. A Generating Facility's summer and winter NR Capability shall be equal to or greater than its summer and winter CNR Capability, respectively.

(b) NI Capability shall be established as follows: For an External ETU with NI Interconnection Service pursuant to Schedule 25 of this OATT, summer and winter NI Capability shall be established as the maximum net MW electrical capability at the Point of Interconnection and shall not exceed applicable seasonal equipment ratings determined pursuant to industry standards and consistent with the specifications described in ISO New England Planning and Operating Procedures. An External ETU's summer and winter NI Capability shall be equal to or greater than its summer and winter CNI Capability, respectively.

II.48.3 Reductions to CNR Capability and CNI Capability: CNR Capability and CNI Capability shall be reduced as follows upon partial or full exit from the Capacity Market as a result of any of the following actions: (1) a voluntary or mandatory termination pursuant to Section III.13.3.4A or Section III.15.A.2.1 of the Tariff results in a reduction to summer and winter CNR Capability (or summer and winter CNI Capability) equal to the respective reduction to summer and winter Qualified Capacity described in III.13.3.4A or Section III.15.A.2.1; (2) a failure to operate commercially for a period of three calendar

years resulting in retirement pursuant to Section III.13.2.5.2.5.3(d) or deactivation pursuant to Section II.52.2 of the Tariff results in a reduction of summer and winter CNR Capability (or summer and winter CNI Capability) to zero; (3) a full exit from the Capacity Market as the result of the operation of a Retirement De-List Bid or a Permanent De-List Bid, described in Section III.13.2.5.2.5.3, or an accepted Deactivation Notification as described in Section II.55 results in a reduction of summer and winter CNR Capability (or summer and winter CNI Capability) to zero; and a partial exit from the Capacity Market as the result of the operation of a Retirement De-List Bid or a Permanent De-List Bid, or the operation of an accepted Deactivation Notification that results in a reduction of CNR Capability (or CNI Capability) as described below.

(a) Summer CNR/CNI Capability Following Partial Exit Resulting From De-List Bid or Partial Deactivation Resulting from Deactivation Notification: Following the partial permanent exit from the Capacity Market of a Generating Capacity Resource (or an Import Capacity Resource associated with an External ETU) as a result of the operation of a de-list bid or an accepted Deactivation Notification, the summer CNR Capability of the associated Generating Facility (or the summer CNI Capability of the associated External ETU) shall be reduced to equal the final amount of summer CNR Capability or summer CNI Capability resulting from the operation of the de-list bid or acceptance of the Deactivation Notification.

(b) Winter CNR/CNI Capability Following Partial Exit Resulting From De-List Bid or Partial Deactivation Resulting from Deactivation Notification: Following the partial permanent exit from the Capacity Market of a Generating Capacity Resource (or an Import Capacity Resource associated with an External ETU) as a result of the operation of a de-list bid or an accepted Deactivation Notification, the winter CNR Capability of the associated Generating Facility (or the winter CNI Capability of the associated External ETU) shall be reduced to equal the final amount of winter CNR Capability or winter CNI Capability resulting from the operation of the de-list bid or acceptance of the Deactivation Notification.

II.48.4 Reductions to NR Capability and NI Capability: NR Capability and NI Capability shall be reduced as follows for Generating Facilities and External ETUs as a result of any of the following actions: (1) a partial or full voluntary retirement or deactivation results in partial or full reduction of NR Capability or NI Capability for a resource that ~~has never held~~ holds no Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service; (2) a failure to operate commercially for a period of three calendar years (as described in Section III.13.2.5.2.5.3(d) or II.-52.2 of

the Tariff) results in a reduction of NR Capability or NI Capability to zero; (3) a full retirement or deactivation of a Generating Facility or an External ETU as the result of the operation of a Retirement De-List Bid or an unconditional Permanent De-List Bid (as described in Section III.13.1.2.4.1(a) and Section III.13.2.5.2.5.3 of the Tariff), or accepted Deactivation Notification, that results in a reduction of NR Capability or NI Capability to zero; and a partial retirement or deactivation as the result of the operation of a Retirement De-List Bid or an unconditional Permanent De-List Bid, or an accepted Deactivation Notification, that results in a reduction of NR Capability or NI Capability as described below.

(a) Summer NR/NI Capability Following Partial Retirement Resulting From De-List Bid or Partial Deactivation Resulting from Deactivation Notification: Following the partial retirement or deactivation of a Generating Facility (or an External ETU) as a result of the operation of a de-list bid or an accepted Deactivation Notification, the summer NR Capability of the Generating Facility (or summer NI Capability of the External ETU) shall be reduced to equal the final amount of summer NR Capability or summer NI Capability resulting from operation of the de-list bid or acceptance of the Deactivation Notification.

(b) Winter NR/NI Capability Following Partial Retirement Resulting From De-List Bid or Partial Deactivation Resulting from Deactivation Notification: Following the partial retirement or deactivation of a Generating Facility (or an External ETU) as a result of the operation of a de-list bid or an accepted Deactivation Notification, the winter NR Capability of the Generating Facility (or winter NI Capability of the External ETU) shall be reduced to equal the final amount of winter NR Capability or winter NI Capability resulting from the operation of the de-list bid or acceptance of the Deactivation Notification.

However, if the resulting winter NR Capability (or winter NI Capability) is less than the Generating Facility's winter CNR Capability (or External ETU's winter CNI Capability), the winter NR Capability (or winter NI Capability) will be set equal to the winter CNR Capability (or winter CNI Capability).

II.I. DEACTIVATION

II.52 Deactivation Notification Process: The Deactivation Notification process described in Section II.I shall be effective for Deactivation Notifications associated with deactivations occurring during the Capacity Commitment Period beginning on June 1, 2028 and all subsequent Capacity Commitment Periods.

II.52.1 Deactivation Notification Deadline: The Deactivation Notification Deadline shall be the first Business Day occurring within 12 months of the first day of each Capacity Commitment Period**.** Deactivation Notifications shall be subject to the reliability review process described in this Section II.I and shall be reviewed by the Internal Market Monitor pursuant to Section III.A.24.

II.52.2 Deactivations Requiring Deactivation Notification: On or before the Deactivation Notification Deadline for the relevant Capacity Commitment Period, but no earlier than the preceding Deactivation Notification Deadline, a Lead Market Participant seeking to permanently remove all or a portion of a resource from the Capacity Market shall submit a Deactivation Notification specifying whether the Lead Market Participant is seeking: (a) a Capacity Market Deactivation; or (b) a New England Markets Deactivation, for the resource. ~~No Deactivation Notification may result in a resource's Capacity Supply Obligation being less than its Rationing Minimum Limit unless the Deactivation Notification is for the entire resource~~. No Deactivation Notification may result in a resource's or External Elective Transmission Upgrade's final CNR Capability or CNI Capability exceeding its final NR Capability or NI Capability, respectively. For the purposes of this Section II.I, the ~~-~~entity authorized to submit a Deactivation Notification on behalf of an External Elective Transmission Upgrade shall be treated as the Lead Market Participant and the External Elective Transmission Upgrade shall be treated as the deactivating resource. For the purposes of this Section II.I, a Market Participant holding equivalent CNR Capability and seeking to permanently remove a resource, or portion thereof, from the Capacity Market shall be treated as if it holds CNR capability and shall be subject to the deactivation process described herein.

A resource that ~~has never held~~ holds no Capacity Network Resource Interconnection Service, Capacity Network Import Interconnection Service, or equivalent CNR Capability shall not be required to submit a Deactivation Notification and may deactivate by notifying the ISO in writing of its election to deactivate and the date of deactivation. The ~~i~~Interconnection ~~rights~~ Service (or equivalent) for the resource will terminate and the status of the resource will be converted to deactivated on the date of deactivation. The date specified for deactivation is subject to the limit for resource inactivity described below.

A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be deactivated regardless of whether a Deactivation Notification was submitted. The ~~i~~Interconnection ~~rights~~ Service for the resource (or equivalent, pursuant to Section II.48.5.3) will terminate and the status of the resource will be converted to deactivated on the date of deactivation. Where a resource has submitted an application to repower, for a Material Modification under Schedule 22, ~~or~~ 23, or 25 of the OATT, or has otherwise obtained approval for modification of its interconnection through the appropriate interconnecting entity pursuant to Section II.48.5.3, the current ~~i~~Interconnection Service~~space~~ will be maintained beyond the three years unless the application under Schedule 22 ~~or~~ , 23, 25, or Section II.48.5.3, is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 ~~or~~, 23, 25, or Section II.48.5.3, the three-year period will be calculated from the last day of commercial operation of the resource.

II.52.3 Deactivation Notification Package: All Deactivation Notifications must be detailed in a Deactivation Notification Package submitted by the Lead Market Participant associated with a deactivation to the ISO no later than the Deactivation Notification Deadline. Deactivation Notifications may not be modified or withdrawn after the Deactivation Notification Deadline unless otherwise permitted pursuant to this Section II.I. The Deactivation Notification Package requirements shall be published on the ISO's website, subject to update, and shall include the following information: (1) the name of the entity submitting the Deactivation Notification, including its affiliates and ultimate parent company; (2) the resource subject to the Deactivation Notification, including the resource's name and resource identification number; (3) whether the Deactivation Notification is for a Capacity Market Deactivation or a New England Markets Deactivation; ~~,~~ (4) ~~the MW amount deactivating, and~~ whether it is a full or partial deactivation; (5) the final amount of CNR Capability (or equivalent) or CNI Capability, and NR Capability (or equivalent) or NI Capability resulting from a New England Markets Deactivation, or the final amount of CNR Capability (or equivalent) or CNI Capability resulting from a Capacity Market Deactivation; and (6) the date of the resource's planned deactivation. For Deactivation Notifications subject to review by the Internal Market Monitor pursuant to Section III.A.24, Lead Market Participants must include in their Deactivation Notification Package the relevant cost workbooks and supporting information described in Section III.A.24. The Deactivation Notification Package shall also include 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 ~~listed~~ Capacity ~~r~~Resource, 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 Internal Market Monitor.

II.52.4 Publication of Deactivation Notifications: No later than ten Business Days after the Deactivation Notification Deadline, the ISO shall post on its website information concerning submitted Deactivation Notifications, including the resource name, the MW quantity of reduction in CNR Capability (or equivalent) or CNI Capability ~~Interconnection Service (MW Quantity)~~ that would result from acceptance of the Deactivation Notification, and the resource's planned deactivation date. Planned deactivation dates shall be updated for those resources accelerating deactivation pursuant to Section II.55.3.

II.53 Deactivation Notification Reliability Review

II.53.1 Deactivation Notification Reliability Review: For each Capacity Commitment Period corresponding to a given Deactivation Notification Deadline, the ISO shall within 90 calendar days of the Deactivation Notification Deadline review all Deactivation Notifications ~~of~~ representing more than 20 MW of CNR Capability, CNI Capability, or equivalent CNR Capability ~~or more~~ in either season and determine whether a resource associated with any Deactivation Notification is needed for reliability reasons. The capacity associated with a Deactivation Notification shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. The capacity associated with a Deactivation Notification shall be deemed needed for reliability only for the sole purpose of addressing a local transmission reliability issue. If review of a Deactivation Notification results in the identification of a reliability need, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. If delaying the deactivation of one or more resources will resolve the identified reliability need, the ISO shall determine based on a review of net going forward costs (as determined pursuant to Section III.A.24), and in consultation with the Reliability Committee, whether a resource may be eligible for delayed deactivation. The Lead Market Participant associated with a resource eligible for delayed deactivation shall be notified as soon as practicable following the ISO's consultation with the Reliability Committee that the capacity associated with a Deactivation Notification is eligible for delayed deactivation. The Lead Market Participant for a resource eligible for delayed deactivation must respond to the ISO within 30 calendar days indicating whether it accepts the delayed deactivation.

II.53.2 Publication of Delayed Deactivations: No later than 90 calendar days after the Deactivation Notification Deadline, the ISO shall post on its website its determinations regarding any Deactivation Notification where the resource elected to delay deactivation to satisfy a reliability need.

II.54 Compensation of Resources Delaying Deactivation

II.54.1 Compensation Election of Resources Delaying Deactivation: If the ISO determines that a resource is eligible for delayed deactivation and the Lead Market Participant associated with that resource accepts the delayed deactivation pursuant to Section II.53, the resource ~~shall be paid~~may elect compensation either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved net going forward costs for the relevant Capacity Commitment Period as determined and filed pursuant to Section III A.24, instead of the Capacity Clearing Price; or (ii) in instances where an entire resource is electing to delay deactivation, under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within 30 days of the ISO's notification that the resource is eligible for delayed deactivation. A resource that elects delayed deactivation that does not notify the ISO of its compensation election as described in this Section II.54 will be paid on the basis of the resource's net going forward costs. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. Cost-of-service agreements must include a claw-back provision addressing the obligation of a resource delaying deactivation that later seeks to return to New England Markets to refund to the ISO with interest all costs, less depreciation, for repairs and capital expenditures that were needed to continue operation of the resource while the resource was subject to a cost-of-service agreement; credits associated with any refund shall be allocated in the same manner as the charges associated with the cost-of-service agreement. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Deactivation Notification was submitted. A resource that has delayed deactivation due to a reliability need shall deactivate as of the first day of the first Capacity Commitment Period in which they are no longer necessary for reliability. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the deactivation was delayed, payment will continue to be pursuant to this Section II.54. Resources that elect payment based on the Commission-approved net going forward costs may file with the Commission pursuant to Section 205 of the Federal Power Act to update its net going forward costs if the resource is retained for reliability for a period longer than the Capacity Commitment Period for which the deactivation was initially delayed.

II.54.2 Allocation of Costs Associated with Delayed Deactivation: The difference between payments based on resource net going forward costs or cost-of-service compensation as detailed in this Section II.54

and payments based on the market clearing price for the Capacity Market under Section III.15 shall be allocated to Regional Network Load within the affected Reliability Region.

II.54.3 Compensation for Delayed Deactivation of Stations Having Common Costs: If a deactivation that is associated with a Station having Common Costs is delayed for reliability reasons, the Generating Capacity Resource will be paid as follows: (i) if one or more Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Seasonal Capacity Auction and one or more Generating Capacity Resource deactivations are delayed for reliability, then the Generating Capacity Resource deactivations delayed for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets composing the Generating Capacity Resource subject to delayed deactivation; or (ii) if no Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Seasonal Capacity Auction and one or more Generating Capacity Resource deactivations are delayed for reliability, then each Generating Capacity Resource deactivation delayed for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Generating Capacity Resources delaying deactivation for reliability purposes).

II.54.4 Amended Obligations of a Cost of Service Agreement: If the ISO is a party to a cost-of-service agreement filed after January 1, 2019 that changes any resource performance-related obligations contained in Section III, Appendix I (provided that those obligations are different than the obligations of a Generating Capacity Resource with a Capacity Supply Obligation), no later than 30 days after such agreement is filed with the Commission, the ISO shall provide to stakeholders quantitative and qualitative information on the need for, and the impacts of, the proposed changes.

II.54.5 Incremental Cost of Reliability Service for Resources Delaying Deactivation: In cases where a Generating Capacity Resource, Demand Capacity Resource, or Distributed Energy Capacity Resource has delayed deactivation for reliability reasons pursuant to Section II.53, and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section II.54.5 must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section II.54.5, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section II.54.1, the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

II.55 Deactivation Acceptance

II.55.1 Notification to Lead Market Participant: No later than 90 days after the Deactivation Notification Deadline, the ISO shall notify the Lead Market Participant: (1) that the Deactivation Notification has been accepted; (2) whether a resource associated with the Deactivation Notification is eligible for delayed deactivation; and (3) whether the Deactivation Notification represents a failure of the conduct test that may be subject to a Proxy Capacity Offer. Lead Market Participants identified pursuant to Section III.A.24 as submitting a Deactivation Notification in order to exercise market power to the benefit of a portfolio may be subject to referral to the Commission's Office of Enforcement and the capacity associated with their Deactivation Notification shall be subject to a Proxy Capacity Offer pursuant to Section III.15.4 during ~~the~~ any of the first two Capacity Commitment Periods of a deactivation where the deactivation results in a portfolio benefit pursuant to Section III.A.24.6. ~~associated with the Deactivation Notification pursuant to Section III.15.4.~~

II.55.2 Accepted Deactivation Notifications: A resource, or portion thereof, that has had a Deactivation Notification accepted by the ISO shall be ineligible to participate in the ~~Capacity Market~~Seasonal Capacity Auction coincident with the commencement of the Capacity Commitment Period of deactivation identified in the Deactivation Notification. The ~~i~~Interconnection ~~rights~~Service (or equivalent), or relevant portion thereof, for the resource will terminate on the deactivation date and the status of the resource, or portion thereof, will be converted to deactivated on the date of deactivation, consistent with the provisions of Section II.48.3 and Schedules 22, 23, and 25 of the OATT. For those resources that specified Capacity Market Deactivation in their Deactivation Notification, only the CNR Capability (or equivalent) or CNI Capability ~~interconnection rights~~, or relevant portion thereof, for the resource will be adjusted downward to reflect the Capacity Market Deactivation, consistent with Section II.48.3 and the relevant provisions of Schedules 22, 23, and 25 of the OATT. Resources that have submitted a Deactivation Notification shall continue participation in New England Markets consistent with the rights and obligations described in Section III.15.7 until the date specified in the resource's accepted Deactivation Notification.

II.55.3 Accelerated Deactivation: A resource, or portion thereof, that is to be deactivated pursuant to Section II.55.2 may deactivate the resource, or portion thereof, earlier than the deactivation date~~Capacity Commitment Period~~ for which its Deactivation Notification was submitted if: (1) the Lead Market Participant has received the notification accepting the Deactivation Notification and responds to request an earlier deactivation date ~~earlier than 12 months after the Deactivation Notification Deadline;~~ (2) the Lead Market Participant sought and received written notification from the Internal Market Monitor

confirming eligib~~il~~ility for accelerated deactivation; and (3) the resource has ~~is able to~~ transfe~~r~~rred any of its remaining Capacity Supply Obligation to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.15.6 or Monthly Reconfiguration Auctions as described in Section III.15.5. A resource, or portion thereof, electing accelerated deactivation pursuant to this Section II.55.3 that has satisfied the above-described obligations must notify the ISO in writing of its election to deactivate and the date of deactivation. The ~~i~~Interconnection ~~rights~~Service (or equivalent), or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to deactivated on the date of deactivation, consistent with the treatment of accepted Deactivation Notifications described in Section II.55.2.

ATTACHMENT K

REGIONAL SYSTEM PLANNING PROCESS

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(d) Posting of LSP Project Status

Each PTO will be individually responsible for publicly posting and updating the status of its respective LSP and the transmission projects arising therefrom on its company website. The ISO's posting of the RSP Project Lists will include links to each PTO's specific LSP posting to be provided to the ISO by the PTOs.

4. Procedures for the Conduct of Needs Assessments, Treatment of Market Responses and Evaluation of Regulated Transmission Solutions

4.1 Needs Assessments

The regional system planning process established in this Attachment K has four different processes. Except as otherwise provided in Section 16 of this Attachment, the reliability planning process established in Section 4 of this Attachment K shall apply to all transmission solutions adopted to resolve a reliability need, and the system efficiency planning process established in Section 17 of this Attachment K shall apply to all transmission solutions adopted to resolve a system efficiency need. The public policy planning process established in Section 4A of this Attachment K shall apply to all transmission solutions adopted to resolve a public policy need. The longer-term transmission planning procedures established in Section 16 of this Attachment K shall apply to all transmission solutions adopted to resolve a longer-term need, and may apply to a non-time-sensitive reliability or system efficiency need to the extent identified by the ISO and combined with longer-term needs in a request for proposal(s) requested by NESCOE in accordance with Section 16.4(a) of this Attachment K.

For needs identified initially as reliability, system efficiency or public policy needs, the collateral benefits of potential solutions to those needs shall not change the planning process applicable to those identified needs; notwithstanding the foregoing, the ISO shall report its views as to whether a project or preferred solution may also satisfy identified reliability needs of the system as described in Section 4A.8 of this Attachment K.

Sections 4.1 through 4.3 of this Attachment are not applicable to the planning of Public Policy Transmission Upgrades, which is governed instead by Section 4A of this Attachment. Sections 4.1 through 4A of this Attachment are not applicable to the planning of Longer-Term Transmission Upgrades, which is governed instead by Section 16 of this Attachment. Sections 4.1 to 4.3 of this

Attachment K are not applicable to the planning of System Efficiency Transmission Upgrades, which is governed instead by Section 17 of this Attachment K.

On a regular and ongoing basis, the ISO, in coordination with the PTOs and the Planning Advisory Committee, shall conduct assessments (i.e., Needs Assessments) of the adequacy of the PTF system, as a whole or in part, to maintain the reliability of such facilities. A Needs Assessment shall analyze whether the PTF in the New England Transmission System: (i) meet applicable reliability standards; (ii) have adequate transfer capability to support local, regional, and inter-regional reliability; (iii) are sufficient to integrate new resources and loads on an aggregate or regional basis; or (iv) otherwise examine various aspects of its performance and capability. A Needs Assessment shall also identify: (i) the location and nature of any potential problems with respect to the PTF and (ii) situations that significantly affect the reliable and efficient operation of the PTF along with any critical time constraints for addressing the needs of the PTF to facilitate the development of market responses and to initiate the pursuit of regulated transmission solutions.

(a) Triggers for Needs Assessments

The ISO, in coordination with the PTOs and the Planning Advisory Committee, shall perform Needs Assessments, inter alia, as needed to:

- Assess compliance with reliability standards and criteria (including those established by the ISO, NERC, and NPCC) consistent with the long-term needs of the system.
- Assess the adequacy of the transmission system capability, such as transfer capability, to support local, regional and interregional reliability.
- Assess sufficiency of the system to integrate new resources and loads on an aggregate or regional basis as needed for the reliable and efficient operation of the system.
- Analyze various aspects of system performance. (Including but not limited to, transient network analysis, small signal analysis, electromagnetic transients program analysis, or delta P analysis).
- Examine short circuit performance of the system.

- Assess the ability to efficiently operate and maintain the transmission system.

- Address system performance as otherwise deemed appropriate by the ISO.

(b) [RESERVED]

(c) Reliability Committee Update Regarding Delayed Deactivations

Prior to the annual Qualification Data Submission Deadline, the ISO shall present to the Reliability Committee the status of any resources delaying deactivation that are being studied in the regional system planning process.

(d) Notice of Initiation of Needs Assessments

Prior to its commencement, the ISO shall provide notice of the initiation of a Needs Assessment to the Planning Advisory Committee consistent with Section 2 of this Attachment.

(e) Preparation of Needs Assessment

Needs Assessments may examine transmission adequacy, and other relevant factors as may be agreed upon from time to time. Needs Assessments shall also consider the views, if any, of the Planning Advisory Committee, State regulators or agencies, NESCOE, the Market Advisor to the ISO Board of Directors, and the ISO Board of Directors. A corresponding assessment shall be performed by the PTOs to identify any needs relating to the Non-PTF transmission facilities (of whatever voltage) that could affect the provision of Regional Transmission Service over the PTF.

(f) Treatment of Market Responses in Needs Assessments

The ISO shall reflect proposed market responses in the regional system planning process. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation), and Elective Transmission Upgrades.

In performing Needs Assessments, the ISO shall rely on certain resources to prevent the identification of system needs. Specifically, the ISO shall incorporate or update information regarding future resources, with the exception of imports across external tie lines, in Needs Assessments that have been proposed and (i) have cleared in a Forward Capacity Auction or ~~Annual~~ Seasonal Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been

selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) have been forecast in the ISO's Forecast Report of Capacity, Energy, Loads and Transmission. The ISO shall also incorporate or update information regarding all existing resources, with the exception of imports across external tie lines, in Needs Assessments. Imports across future or existing external tie lines will not be relied upon unless such imports (i) have a Capacity Supply Obligation corresponding to the year of study, (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) may be represented by a minimum flow based on HQ Interconnection Capability Credits. The ISO will model out-of-service, for the relevant period, all submitted Deactivation Notifications, Retirement De-List Bids, and Permanent De-List Bids. With respect to having been selected in, and being contractually bound by a state-sponsored request for proposals, or having a financially binding obligation pursuant to a contract, demonstration of such contracts is accomplished through submittal for ISO review of an order or other similar authorization from the appropriate state regulatory agency, along with a copy of the contract, that together demonstrate the contractual requirements. These documents may be submitted by: the Project Sponsor; the state regulatory agency authorizing the contract; a transmission company that is a counterparty to the contract; or by a third-party organization representing the interests of the New England states regarding energy related issues, such as NESCOE. The ISO shall incorporate or update information regarding a proposed Elective Transmission Upgrade in a Needs Assessment at a time after the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which an Elective Transmission Upgrade Interconnection Agreement has been executed and, to the extent required, filed and accepted by the Commission, or filed unexecuted and accepted by the Commission. In the case where the Elective Transmission Upgrades are proposed in conjunction with the interconnection of a resource, these Elective Transmission Upgrades shall be considered at the same time as the proposed resource is considered in the Needs Assessment provided that the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which an Elective Transmission Upgrade Interconnection Agreement has been executed and, to the extent required, filed and accepted by the Commission, or filed unexecuted and accepted by the Commission.

regional system planning process, and why other suggested transmission needs driven by federal Public Policy Requirements not identified by NESCOE will not be evaluated. In addition, the ISO will post on its website an explanation of those transmission needs driven by local Public Policy Requirements that will be evaluated for potential transmission solutions in the regional system planning process, and why other suggested transmission needs driven by local Public Policy Requirements will not be evaluated.

4A.2 Preparation for Conduct of Public Policy Transmission Studies; Stakeholder Input

Upon receipt of the NESCOE request, or as the result of the ISO's consideration of a federal or local Public Policy Requirement pursuant to Section 4A.1.1, the ISO will prepare and post on its website a proposed scope for the Public Policy Transmission Study, and associated parameters and assumptions (including resource assumptions), and provide the foregoing to the Planning Advisory Committee by no later than September 1 of the request year. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit stakeholder input for consideration by the ISO on the study's scope, parameters and assumptions.

4A.3 Public Policy Transmission Studies

(a) Conduct of Public Policy Transmission Studies; Stakeholder Input

With input from Planning Advisory Committee and potentially impacted PTOs, the ISO will perform the initial phase of the Public Policy Transmission Study to develop a rough estimate of the costs and benefits of high-level concepts that could meet transmission needs driven by Public Policy Requirements. The study's results will be posted on the ISO's website, and a meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input on the results of the initial phase of the study, and the scope, parameters and assumptions (including resource assumptions) for any follow-on phase of the study. The ISO may − as a follow-on phase of the Public Policy Transmission Study − perform more detailed analysis and engineering work on the high-level concepts.

(b) Treatment of Market Solutions in Public Policy Transmission Studies

The ISO shall reflect proposed market responses in the Public Policy Transmission Study. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation), Merchant Transmission Facilities and Elective Transmission Upgrades.

In performing Public Policy Transmission Studies, the ISO shall rely on certain resources to prevent the identification of transmission needs driven by Public Policy Requirements. Specifically, the ISO shall incorporate in the Public Policy Transmission Study information regarding future resources, with the exception of imports across external tie lines, that have been proposed and (i) have cleared in a Forward Capacity Auction or ~~Annual~~ Seasonal Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) have been forecast in the ISO's Forecast Report of Capacity, Energy, Loads and Transmission. The ISO shall also incorporate or update information regarding all existing resources, with the exception of imports across external tie lines, in Public Policy Transmission Studies. Imports across future or existing external tie lines will not be relied upon unless such imports (i) have a Capacity Supply Obligation corresponding to the year of study, (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) may be represented by a minimum flow based on HQ Interconnection Capability Credits. The ISO will model out-of-service, for the relevant period, all submitted Deactivation Notifications, Retirement De-List Bids, and Permanent De-List Bids. With respect to having been selected in, and being contractually bound by a state-sponsored request for proposals, or having a financially binding obligation pursuant to a contract, demonstration of such contracts is accomplished through submittal for ISO review of an order or other similar authorization from the appropriate state regulatory agency, along with a copy of the contract, that together demonstrate the contractual requirements. These documents may be submitted by: the Project Sponsor; the state regulatory agency authorizing the contract; a transmission company that is a counterparty to the contract; or by a third-party organization representing the interests of the New England states regarding energy related issues, such as NESCOE. The ISO shall incorporate information regarding a proposed Merchant Transmission Facility or Elective Transmission Upgrade in a Public Policy Transmission Study at a time after the studies corresponding to the Merchant Transmission Facility or Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), and a commercial operation date has been ascertained, with the exception of Elective Transmission Upgrades that are proposed in conjunction with the

interconnection of a resource, which shall be considered at the same time as the proposed resource is considered in the Public Policy Transmission Study.

4A.4 Response to Public Policy Transmission Studies

The results of the Public Policy Transmission Study will be provided to the Planning Advisory Committee and posted on the ISO's website, and a meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input for the ISO on those results, including any updates from the states on any methods by which they are satisfying their respective Public Policy Requirements included in the Public Policy Transmission Study. The ISO's costs of performing the Public Policy Transmission Study described in Section 4A.3 will be collected by the ISO pursuant to Schedule 1 of Section IV.A of the Tariff. Any prudently incurred PTO costs for assistance requested by the ISO to support the Public Policy Transmission Study will be recovered by the applicable PTO(s) in accordance with Attachment F and Schedule 21 of the Tariff.

The ISO will evaluate the input from the Planning Advisory Committee and provide the results of the Public Policy Transmission Study to Qualified Transmission Project Sponsors for their use in preparing Stage One Proposals to develop, build and operate one or more projects consistent with the general design requirements identified by the ISO in the study.

4A.5 Use and Control of Right of Way

Neither the submission of a project by a Qualified Transmission Project Sponsor nor the selection by the ISO of a project submitted by a Qualified Transmission Project Sponsor for inclusion in the RSP Project List shall alter a PTO's use and control of an existing right of way, the retention, modification, or transfer of which remain subject to the relevant law or regulation, including property or contractual rights, that granted the right-of-way. Nothing in the processes described in this Attachment K requires a PTO to relinquish any of its rights-of-way in order to permit a Qualified Transmission Project Sponsor to develop, construct or own a project.

4A.6 Stage One Proposals

(a) Information Required for Stage One Proposals

Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution).

(b) Resolution Through Informal Negotiations

To the extent that the Planning Advisory Committee is not able to resolve a dispute arising under this Attachment involving a Reviewable Determination, as defined in Section 12.4 of this Attachment, between and among the ISO, the Disputing Party, and, as appropriate, the affected Transmission Owner, such dispute shall be the subject of good-faith negotiations among the Parties. Each Party shall designate a fully authorized senior representative for resolution on an informal basis as promptly as practicable.

(c) Resolution Through Alternative Dispute Resolution

In the event the designated representatives are unable to resolve the dispute through informal negotiation within thirty (30) days, or such other period as the Parties may agree upon, by mutual agreement of the Parties, such dispute may be submitted to mediation or any other form of alternative dispute resolution upon the agreement of all Parties to participate in such mediation or other alternative dispute resolution process. Such form of alternative dispute resolution shall not include binding arbitration.

If a Party identifies exigent circumstances reasonably requiring expedited resolution of the dispute, such Party may file a Complaint with the Commission or seek other appropriate redress before a court of competent jurisdiction.

12.7 Notice of Dispute Resolution Process Results

Within three (3) Business Days following the resolution of a dispute pursuant to either Section 12.6(b) or Section 12.6(c) of this Attachment, the ISO shall distribute to the Planning Advisory Committee a document reflecting the resolution.

13. Rights Under The Federal Power Act

Nothing in this Attachment shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

14. Annual Assessment of Transmission Transfer Capability

Each year, the ISO shall issue the results of the annual assessment of transmission transfer capability, conducted pursuant to applicable NERC, NPCC and ISO New England standards and criteria and the identification of potential future transmission system weaknesses and limiting facilities that could impact the transmission system's ability to reliably transfer energy in the planning horizon. Each annual assessment will identify those portions of the New England system, along with the associated interface boundaries, that should be considered in the assessment of Summer and Winter Capacity Commitment Period Capacity Zones to be modeled in the ~~Forward~~ Capacity Market ~~or Annual Capacity Market~~ pursuant to ISO Tariff Section III.12. This report will be posted on the ISO website. Each annual assessment will model out-of-service resources associated with the following, if the ISO determines the removal of the resource is likely to have an impact on the transmission transfer limits for the relevant period: Deactivation Notifications, Retirement De-List Bids, and Permanent De-List Bids.

15. Procedures for the Conduct of Cluster Enabling Transmission Upgrades Regional Planning Study

The purpose of this Section 15 is to support the conduct of Interconnection Studies under the Interconnection Procedures set forth in Schedules 22, 23 and 25 of Section II of the Tariff. Other than Section 2 of this Attachment K regarding the responsibilities of the Planning Advisory Committee and this Section 15, none of the other provisions in this Attachment K apply to the conduct of the Cluster Enabling Transmission Upgrade Regional Planning Study or the results of the study.

15.1 Notice of Initiation of Cluster Enabling Transmission Upgrade Regional Planning Study in Support of Cluster Studies under the Interconnection Procedures.

Pursuant to Section 4.2.2 of Schedule 22, Section 1.5.3.2 of Schedule 23, and Section 4.2.2 of Schedule 25 of Section II of this Tariff, the ISO shall provide notice to the Planning Advisory Committee of the initiation Cluster Enabling Transmission Upgrade ("CETU") Regional Planning Study ("CRPS") (the cost of which will be recovered by the ISO pursuant to Schedule 1 of Section IV.A of the Tariff). The results of the CRPS will inform the Cluster Study and Transitional Cluster Study entry process and requirements for Interconnection Requests for Generating Facilities and Elective Transmission Upgrades that the System Operator determines need the CETU to meet the standards described in Sections 3.2.1 and 3.2.2 Schedules 22, 23, and 25 of Section II of the Tariff.

15.2 Preparation for Conduct of CRPS; Stakeholder Input

The ISO shall use the System Efficiency Needs Scenario, factors in Section 17.10 of this Attachment and Section B.1 of Attachment N to identify instances where system efficiency production cost savings at a given part of the system are equal to or greater than $4.3 million/year on the PTF portion of the New England Transmission System and, as applicable, identify system efficiency needs on the PTF portion of the New England Transmission System.

All of the system efficiency issues and associated benefits of relieving those issues will be documented in a System Efficiency Needs Assessment conducted pursuant to Section 17 of this Attachment.

Any system efficiency production cost savings equal to or greater than $4.3 million/year determined using the factors in Section 17.10 of this Attachment and Section B.1 of Attachment N will be identified as system efficiency needs, and a request for proposal or multiple requests for proposals will be issued to initiate the competitive solution process for System Efficiency Transmission Upgrades to address the identified system efficiency need or needs pursuant to Section 17.12 of this Attachment.

17.10 Treatment of Market Responses in System Efficiency Needs Assessments

The ISO shall reflect proposed market responses in the regional system planning process. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation), and Elective Transmission Upgrades.

In performing System Efficiency Needs Assessments, the ISO shall incorporate or update information regarding future resources, with the exception of imports across external tie lines, in System Efficiency Needs Assessments that have been proposed and (i) have cleared in a Forward Capacity Auction or ~~Annual~~ Seasonal Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) have been forecast in the ISO's Forecast Report of Capacity, Energy, Loads and Transmission. The ISO shall also incorporate or update information regarding all existing resources, with the exception of imports across external tie lines, in System Efficiency Needs Assessments. For imports, if a tie line from an external area has an associated energy contract, the minimum energy interchange will be respected. Otherwise, imports and exports will be reflective of the least cost economic dispatch. The ISO will model out-of-service, for the relevant period, all submitted

Deactivation Notifications, Retirement De-List Bids, and Permanent De-List Bids. With respect to having been selected in, and being contractually bound by a state-sponsored request for proposals, or having a financially binding obligation pursuant to a contract, demonstration of such contracts is accomplished through submittal for ISO review of an order or other similar authorization from the appropriate state regulatory agency, along with a copy of the contract, that together demonstrate the contractual requirements. These documents may be submitted by: the Project Sponsor; the state regulatory agency authorizing the contract; a transmission company that is a counterparty to the contract; or by a third-party organization representing the interests of the New England states regarding energy related issues, such as NESCOE. The ISO shall incorporate or update information regarding a proposed Elective Transmission Upgrade in a System Efficiency Needs Assessment at a time after the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which an Elective Transmission Upgrade Interconnection Agreement has been executed and, to the extent required, filed and accepted by the Commission, or filed unexecuted and accepted by the Commission. In the case where the Elective Transmission Upgrades are proposed in conjunction with the interconnection of a resource, these Elective Transmission Upgrades shall be considered at the same time as the proposed resource is considered in the System Efficiency Needs Assessment provided that the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained and for which an Elective Transmission Upgrade Interconnection Agreement has been executed and, to the extent required, filed and accepted by the Commission, or filed unexecuted and accepted by the Commission.

17.11 System Efficiency Needs Assessment Support

For the development of System Efficiency Needs Assessments, the ISO will coordinate with the PTOs and the Planning Advisory Committee to support the ISO's performance of System Efficiency Needs Assessments. To facilitate this support, the ISO will post on its website the models, files, cases, contingencies, assumptions and other information used to perform System Efficiency Needs Assessments. The ISO may establish requirements that any PTO or member of the Planning Advisory Committee must satisfy in order to access certain information used to perform System Efficiency Needs Assessments, due to ISO New England Information Policy and CEII constraints. The ISO may ask PTOs or Planning Advisory Committee members with special expertise to provide technical support or perform studies

I.2 Rules of Construction; Definitions

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I.2.2. Definitions:

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

***

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

***

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

***

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

Capacity Commitment Period is the ~~one-year~~ period ~~from June 1 through May 31~~ for which obligations are assumed and payments are made in the ~~Forward~~ Capacity Market ~~and Annual Capacity Market.~~ For the Capacity Commitment Periods occurring prior to June 1, 2028, the Capacity Commitment Period is the one-year period from June 1 through May 31. For all Capacity Commitment Periods beginning on or

after June 1, 2028, there shall be two seasonal Capacity Commitment Periods for which Capacity Supply Obligations are assumed and payments are made in the Capacity Market: a Summer Capacity Commitment Period and a Winter Capacity Commitment Period. For the Summer Capacity Commitment Period beginning on June 1, 2028, the Summer Capacity Commitment Period is the five-month period from June 1, 2028 through October 31, 2028. For all Capacity Commitment Periods thereafter, the Summer Capacity Commitment Period is the six-month period from May 1 through October 31 and the Winter Capacity Commitment Period is the six-month period from November 1 through April 30.

***

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

***

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

***

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

***

CM and SBE Financial Assurance Requirements are described in Section VIII of the ISO New England Financial Assurance Policy.

***

Daily Capacity Market Settlement are those Forward Capacity Market payments and charges identified in Sections III.13.7.1 (except III.13.7.1.3), III.13.7.5.1 (except III.13.7.5.1.1.10), and III.13.7.5.4 or those Seasonal Capacity Market payments and charges described in Sections III.15.8.1, III.15.8.5.1, III.15.8.5.4, and III.15.8.6.

***

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

***

Internal Bilateral for Capacity is a type of internal bilateral transaction described in Section III.15.6.3.

***

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

***

MRI Capacity is the amount, determined pursuant to Section III.15.3, that a Capacity Resource may qualify to offer in a Seasonal Capacity Auction, Monthly Reconfiguration Auction, or Capacity Supply Obligation Bilateral. MRI Capacity shall be either Seasonal MRI Capacity or Monthly MRI Capacity.

***

Net Installed Capacity Requirement is defined in Section III.12.1,

***

Non-Commercial Capacity is the capacity of a resource that cleared in a Forward Capacity Auction for periods prior to the ~~Annual~~ Seasonal Capacity Auction associated with the Capacity Commitment Period beginning on June 1, 2028, or otherwise acquired a Capacity Supply Obligation and remains on Critical Path Schedule monitoring as of June 1, 2028, for some or all of its capacity that acquired a Capacity Supply Obligation.

***

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined prior to the 2028-2029 Capacity Commitment Period in the Forward Capacity Market qualification processes~~, or, for the 2028-2029 Capacity Commitment Period and all Capacity Commitment Periods thereafter, through the Annual Capacity Market qualification and demonstration processes~~.

***

Rationing Minimum Limit is the MW quantity below which a Capacity Offer may not be rationed in the ~~Annual~~ Seasonal Capacity Auction.

***

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

***

Seasonal Capacity Auction is the Summer Capacity Auction or Winter Capacity Auction processes carried out pursuant to Section III.15.4 of Market Rule 1.

***

Seasonal MRI Capacity may refer to the Seasonal MRI Capacity of a Capacity Resource or the Seasonal MRI Capacity of a Capacity Market parameter. The Seasonal MRI Capacity values of a Capacity Resource shall be the summer and winter Marginal Reliability Impact Capacity values determined pursuant to Section III.15.3. The Seasonal MRI Capacity of a Capacity Market parameter other than that which is assigned to a Capacity Resource pursuant to Section III.15.3 shall be the MRI equivalent of the value developed pursuant to Section III.12 or Section III.15.

***

Transition Seasonal MRI Capacity may refer to the Transition Seasonal MRI Capacity of a Capacity Resource or the Transition Seasonal MRI Capacity of a Capacity Market parameter. The Transition Seasonal MRI Capacity value of a Capacity Resource is a value calculated pursuant to Section III.15.B.1 to be used in place of a Capacity Resource's Seasonal MRI Capacity for purposes of the Seasonal Capacity Auctions associated with Capacity Commitment Periods occurring between June 1, 2028 and April 30, 2031. The Transition Seasonal MRI Capacity of a Capacity Market parameter other than that which is assigned to a Capacity Resource pursuant to Section III.15.3 is described in Section III.15.B.2.

***

Winter Capacity Commitment Period is one of two annually occurring Capacity Commitment Periods for which Capacity Supply Obligations are assumed and payments are made in the Seasonal Capacity Auction. The Winter Capacity Commitment Period is the six-month period from November 1 through April 30.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

Overview

The procedures and requirements set forth in this ISO New England Financial Assurance Policy shall govern all Applicants, all Market Participants and all Non-Market Participant Transmission Customers. Capitalized terms used in the ISO New England Financial Assurance Policy shall have the meaning specified in Section I.

The purpose of the ISO New England Financial Assurance Policy is (i) to establish minimum criteria for participation in the New England Markets; (ii) to establish a financial assurance policy for Market Participants and Non-Market Participant Transmission Customers that includes commercially reasonable credit review procedures to assess the financial ability of an Applicant, a Market Participant or a Non-Market Participant Transmission Customer to pay for service transactions under the Tariff and to pay its share of the ISO expenses, including amounts under Section IV of the Tariff, and including any applicable Participant Expenses; (iii) to set forth the requirements for alternative forms of security that will be deemed acceptable to the ISO and consistent with commercial practices established by the Uniform Commercial Code that protect the ISO and the Market Participants against the risk of non-payment by other, defaulting Market Participants or by Non-Market Participant Transmission Customers; (iv) to set forth the conditions under which the ISO will conduct business in a nondiscriminatory way so as to avoid the possibility of failure of payment for services rendered under the Tariff; and (v) to collect amounts past due, to collect amounts payable upon billing adjustments, to make up shortfalls in payments, to suspend Market Participants and Non-Market Participant Transmission Customers that fail to comply with the terms of the ISO New England Financial Assurance Policy, to terminate the membership of defaulting Market Participants and to terminate service to defaulting Non-Market Participant Transmission Customers.

I. GROUPS REGARDED AS SINGLE MARKET PARTICIPANTS

In the case of a group of Entities that are treated as a single Market Participant pursuant to Section 4.1 of the Second Restated NEPOOL Agreement (the "RNA"), the group members shall be deemed to have elected to be jointly and severally liable for all debts to Market Participants, PTOs, Non-Market Participant Transmission Customers, NEPOOL and the ISO of any of the group members. For the purposes of the ISO New England Financial Assurance Policy, the term "Market Participant" shall, in the case of a group of members that are treated as a single Market Participant pursuant to Section 4.1 of the RNA, be deemed to refer to the group of members as a whole, and any financial assurance provided

under the ISO New England Financial Assurance Policy will be credited to the account of the group member with the customer identification at the ISO.

II. MARKET PARTICIPANTS' REVIEW AND CREDIT LIMITS

Solely for purposes of the ISO New England Financial Assurance Policy: a "Municipal Market Participant" is any Market Participant that is either (a) a Publicly Owned Entity except for an electric cooperative or an organization including one or more electric cooperatives as used in Section 1 of the RNA or (b) a municipality, an agency thereof, a body politic or a public corporation (i) that is created under the authority of any state or province that is adjacent to one of the New England states, (ii) that is authorized to own, lease and operate electric generation, transmission or distribution facilities and (iii) that has been approved for treatment as a Municipal Market Participant by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee. Market Participants that are not Municipal Market Participants are referred to as "Non-Municipal Market Participants."

A. Minimum Criteria for Market Participation

Any entity participating or seeking to participate in the New England Markets shall comply with the requirements of this Section II.A. For purposes of this Section II.A, the term "customer" shall refer to both Market Participants and Non-Market Participant Transmission Customers and the word "applicant" shall refer to both applicants for Market Participant status and applicants for transmission service from the ISO.

1. Information Disclosure

(a) Each customer and applicant, on an annual basis (by April 30 each year) shall submit a completed information form in the form of (with only minor, non-material changes) and with the information required by Attachment 6 to the ISO New England Financial Assurance Policy. Customer or applicant shall not be required to disclose information required by Attachment 6 if such disclosure is prohibited by law; provided, however, if the disclosure of any information required by Attachment 6 is prohibited by law, then customer or applicant shall use reasonable efforts to obtain permission to make such disclosure. This information shall be treated as Confidential Information, but its disclosure pursuant to subsection (b) below is expressly permitted in accordance with the terms of the ISO New England Information Policy. Customers and applicants may satisfy the requirements above by providing the ISO with filings made to the Securities

the deficiencies identified in the notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

3. Communications

Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has either established or contracted to establish procedures to effectively communicate with and respond to the ISO with respect to matters relating to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy. Such procedures must ensure, at a minimum, that at least one person with the ability and authority to address matters related to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy on behalf of the customer or applicant, including the ability and authority to respond to requests for information and to arrange for additional financial assurance as necessary, is available from 9:00 a.m. to 5:00 p.m. Eastern Time on Business Days. Such procedures must also ensure that the ISO is kept informed about the current contact information (including phone numbers and e-mail addresses) for the person or people described above. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

4. Capitalization

(a) To be deemed as meeting the capitalization requirements, a customer or applicant shall either:

(i) be Rated and have a Governing Rating that is an Investment Grade Rating of BBB-/Baa3 or higher;

(ii) maintain a minimum Tangible Net Worth of one million dollars; or

(iii) maintain a minimum of ten million dollars in total assets, provided that, to meet this requirement, a customer or applicant may supplement total assets of less than ten million dollars with additional financial assurance in an amount equal to the difference between ten million dollars and the customer's or applicant's total assets in one of the forms described in Section X (any additional financial assurance provided pursuant to this Section II.A.4(a) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy).

(b) Any customer or applicant that fails to meet these capitalization requirements will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions of a duration greater than one month in the FTR system or any future transactions for a duration of one month or less except when FTRs for a month are being auctioned for the final time. Such a customer or applicant may enter into future transaction of a duration of one month or less in the FTR system in the case of FTRs for a month being auctioned for the final time. Any customer or applicant that fails to meet these capitalization requirements shall provide additional financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy equal to 25 percent of the customer's or applicant's FTR Financial Assurance Requirements. Any additional financial assurance provided pursuant to this Section II.A.4(b) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

(c) For markets other than the FTR market:

(i) Where a customer or applicant fails to meet the capitalization requirements, the customer or applicant will be required to provide an additional amount of financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy in an amount equal to 25 percent of the customer's or applicant's total financial assurance requirement, excluding the following:

- FTR Financial Assurance Requirements; and
- FCM Delivery Financial Assurance for customers or applicants that are assessed as medium risk or high risk per the Corporate Liquidity

Assessment (as described in Section VII.A below) from the start of the Capacity Commitment Period related to the sixteenth Forward Capacity Auction (i.e., June 1, 2025) or any Capacity Commitment Period up to the Capacity Commitment Period beginning on June 1, 2028~~thereafter.~~

(ii) An applicant that fails to provide the full amount of additional financial assurance required as described in subsection (i) above will be prohibited from participating in the New England Markets until the deficiency is rectified. For a customer, failure to provide the full amount of additional financial assurance required as described in subsection (i) above will have the same effect and will trigger the same consequences as exceeding the "100 Percent Test" as described in Section III.B.2.c of the ISO New England Financial Assurance Policy.

(iii) Any additional financial assurance provided pursuant to this Section II.A.4(c) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

5. Additional Eligibility Requirements

All customers and applicants shall at all times be:

(a) An "appropriate person," as defined in sections 4(c)(3)(A) through (J) of the Commodity Exchange Act (7 U.S.C. § 1 *et seq.*);
(b) An "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or
(c) A "person who actively participates in the generation, transmission, or distribution of electric energy," as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

Each customer must demonstrate compliance with the requirements of this Section II.A.5 by submitting to the ISO on or before September 15, 2013 a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the customer is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately

or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

III. MARKET PARTICIPANTS' REQUIREMENTS

Each Market Participant that provides the ISO with financial assurance pursuant to this Section III must provide the ISO with financial assurance in one of the forms described in Section X below and in an amount equal to the amount required in order to avoid suspension under Section III.B below (the "Market Participant Financial Assurance Requirement"). A Market Participant's Market Participant Financial Assurance Requirement shall remain in effect as provided herein until the later of (a) 150 days after termination of the Market Participant's membership or (b) the end date of all FTRs awarded to the Market Participant and the final satisfaction of all obligations of the Market Participant providing that financial assurance; provided, however that financial assurances required by the ISO New England Financial Assurance Policy related to potential billing adjustments chargeable to a terminated Market Participant shall remain in effect until such billing adjustment request is finally resolved in accordance with the provisions of the ISO New England Billing Policy. Furthermore and without limiting the generality of the foregoing, (i) any portion of any financial assurance provided under the ISO New England Financial Assurance Policy that relates to a Disputed Amount shall not be terminated or returned prior to the resolution of such dispute, even if the Market Participant providing such financial assurance is terminated or voluntarily terminates its MPSA and otherwise satisfies all of its obligations to the ISO and (ii) the ISO shall not return or permit the termination of any financial assurance provided under the ISO New England Financial Assurance Policy by a Market Participant that has terminated its membership or been terminated to the extent that the ISO determines in its reasonable discretion that that financial assurance will be required under the ISO New England Financial Assurance Policy with respect to an unsettled liability or obligation owing from that Market Participant.

A Market Participant that knows that it is not satisfying its Market Participant Financial Assurance Requirement shall notify the ISO immediately of that fact.

A. Determination of Financial Assurance Obligations

For purposes of the ISO New England Financial Assurance Policy:

(i) a Market Participant's "Hourly Requirements" at any time will be the sum of (x) the Hourly Charges (excluding Daily Capacity Market Settlement~~FCM Charges~~) for such Market Participant that have been invoiced but not paid (which amount shall not be less

than $0), plus (y) the Hourly Charges (excluding Daily ~~F~~Capacity Market ~~Charges~~Settlement) for such Market Participant that have been settled but not invoiced, plus (z) the Hourly Charges (excluding Daily Capacity Market Settlement ~~FCM Charges~~) for such Market Participant that have been cleared but not settled which amount shall be calculated by the Hourly Charges Estimator. The Hourly Charges Estimator (which amount shall not be less than $0) shall be determined by the following formula:

$$\text{Hourly Charges Estimator} = \sum_{i=t-n+1}^{t} HC_i \times \text{LMP ratio} \times 1.15$$

Where:

t = The last day that such Market Participant's Hourly Charges (excluding Daily Capacity Market Settlement ~~FCM Charges~~) are fully settled;

n = The number of days that such Market Participant's Day-Ahead Energy has been cleared but not settled;

HC = The Hourly Charges (excluding Daily Capacity Market Settlement ~~FCM Charges~~) for such Market Participant for a fully settled day; and

LMP ratio = The average Day-Ahead Prices at the New England Hub over the period of cleared but not settled n days divided by the average Day-Ahead Prices at the New England Hub over the period of most recent fully settled n days. For purposes of this Section III.A.(i), the "New England Hub" shall mean the Hub located in Western and Central Massachusetts referred to as .H.INTERNAL_HUB;

(ii) A Market Participant's "Daily ~~F~~CM Requirements" at any time will be the sum of (x) the Daily Capacity Market Settlement~~FCM Charges~~ amounts that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Daily Capacity Market Settlement~~FCM Charges~~ amounts that have been settled but not invoiced, plus (z) the Daily Capacity Market Settlement~~FCM Charges~~ for such Market Participants that have been incurred but not settled, which amount shall be calculated by the Daily ~~F~~CM Obligation Estimator. The Daily ~~F~~CM Obligation Estimator (which amount shall not be less than $0) shall be determined by the following formula:

Daily ~~F~~CM Obligation Estimator = MAX(~~F~~CM_Daily_Credit_CMo x NDAY_CM + ~~F~~CM_Daily_Credit_PM x NDAY_PM + ~~F~~CM_Charge_LD x NDAY_P2 x ~~F~~CA_Price_Ratio, 0)

Where:

~~F~~CM_Daily_Credit_CMo is the portion of the Daily Capacity Market Settlement~~FCM Charges~~ that corresponds to Capacity Supply Obligations for the Market Participant in the current month;

~~F~~CM_Daily_Credit_PM is the portion of the Daily ~~F~~Capacity Market Settlement~~Charges~~ that corresponds to Capacity Supply Obligations for the Market Participant in the month preceding the current month;

NDAY_CM is the number of days in the current month within the period from the last day the Daily ~~F~~Capacity Market Settlement~~Charges~~ have been settled to the current day (when financial assurance is assessed);

NDAY_PM is the number of days in the month preceding the current month within the period from the last day ~~of~~ the Daily Capacity Market Settlement~~FCM Charges~~ payments and charges have been settled to the current day (when financial assurance is assessed);

~~F~~CM_Charge_LD is the portion of the Daily Capacity Market Settlement~~FCM Charges~~ that corresponds to Capacity Load Obligations for the Market Participant from the last day the Daily Capacity Market Settlement~~FCM Charges~~ payments and charges have been settled; and

NDAY_P2 is the number of days from the last day the Daily Capacity Market Settlement~~FCM Charges~~ payment and charges have been settled to the current day (when financial assurance is assessed) plus 2.

The ~~F~~CA_Price_Ratio shall be calculated as the weighted average of the Capacity Clearing Prices for the Rest-of-Pool Capacity Zone for the relevant Capacity Commitment Period~~s~~ divided by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day the Daily Capacity Market Settlement~~FCM Charges~~ payments and charges have been settled, as determined by the following formula:

~~F~~CA_Price_Ratio = (((Clearing Price_CCP_n x NDAY_P2_CCP_n) + (Clearing Price_CCP_{n+1} x NDAY_P2_CCP_{n+1}))/NDAY_P2)/(Clearing Price_CCP_n)

Where:

Clearing Price_CCP_n is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that

contains the last day that the Daily Capacity Market Settlement~~FCM Charges~~ payments and charges have been settled;

Clearing Price_CCP_{n+1} is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone for the Capacity Commitment Period following CCP_n;

$NDAY_P2_CCP_n$ is number of days in the CCP_n within NDAY_P2; and

$NDAY_P2_CCP_{n+1}$ is number of days in the CCP_{n+1} within NDAY_P2.

(iii) a Market Participant's "Non-Hourly Requirements" at any time will be determined by averaging that Market Participant's Non-Hourly Charges but not include: (A) the amount due from or to such Market Participant for FTR transactions, (B) any amounts due from such Market Participant for the ~~Forward~~ Capacity Market or System-Backed Export transactions, (C) any amounts due under Section 14.1 of the RNA, (D) any amounts due for NEPOOL GIS API Fees, and (E) the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Market Participant) over the two most recently invoiced calendar months; provided that such Non-Hourly Requirements shall in no event be less than zero;

(iv) a Market Participant's "Transmission Requirements" at any time will be determined by averaging that Market Participant's Transmission Charges over the two most recently invoiced calendar months; provided that such Transmission Requirements shall in no event be less than $0;

(v) a Market Participant's Virtual Requirements at any time will equal the amount of all unsettled Increment Offers and Decrement Bids submitted by such Market Participant at such time (which amount of unsettled Increment Offers and Decrement Bids will be calculated by the ISO according to a methodology approved from time to time by the NEPOOL Budget and Finance Subcommittee and posted on the ISO's website);

(vi) a Market Participant's "Financial Assurance Obligations" at any time will be equal to the sum at such time of:

a. such Market Participant's Hourly Requirements; plus

b. such Market Participant's Daily ~~F~~CM Requirements; plus

c. such Market Participant's Virtual Requirements; plus

d. such Market Participant's Non-Hourly Requirements times 2.50 (subject to Section X.D with respect to Provisional Members); plus

e. such Market Participant's "FTR Financial Assurance Requirements" under Section VI below; plus

f. such Market Participant's "FCM Financial Assurance Requirements" under Section VII below for Capacity Commitment Periods occurring prior to June 1, 2028, and such Market Participant's "CM and SBE Financial Assurance Requirements" under Section VIII for Capacity Commitment Periods beginning on June 1, 2028 and all Capacity Commitment Periods thereafter (for the avoidance of doubt, Auction Delivery Financial Assurance under Section VIII.A shall not be included in Financial Assurance Obligations)~~-~~; plus

~~g. such Market Participant's "IEP Financial Assurance Requirement" under Section III.D below; plus~~

~~h.~~g. the amount of any Disputed Amounts received by such Market Participant; and

(vii) a Market Participant's "Transmission Obligations" at any time will be such Market Participant's Transmission Requirements times 2.50.

To the extent that the calculations of the components of a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) as described above produce positive and negative values, such components may offset each other; provided, however, that a Market Participant's Financial Assurance Obligations shall never be less than zero.

B. Credit Test Calculations and Allocation of Financial Assurance, Notice and Suspension from the New England Markets

1. Credit Test Calculations and Allocation of Financial Assurance

The financial assurance provided by a Market Participant shall be applied as described in this Section.

(a) "Market Credit Test Percentage" is equal to a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) divided by the sum of its

Market Credit Limit and any financial assurance allocated as described in subsection (d) below.

(b) "FTR Credit Test Percentage" is equal to a Market Participant's FTR Financial Assurance Requirements divided by any financial assurance allocated as described in subsection (d) below.

(c) "Transmission Credit Test Percentage" is equal to a Market Participant's Transmission Obligations divided by the sum of its Transmission Credit Limit and any financial assurance allocated as described in subsection (d) below.

(d) A Market Participant's financial assurance shall be allocated as follows:

(i) financial assurance shall be first allocated so as to ensure that the Market Participant's Market Credit Test Percentage is no greater that 100%;

(ii) any financial assurance that remains after the allocation described in subsection (d) (i) shall be allocated so as to ensure that the Market Participant's FTR Credit Test Percentage is no greater than 100%;

(iii) any financial assurance that remains after the allocation described in subsection (d) (ii) shall be allocated so as to ensure that the Market Participant's Transmission Credit Test Percentage is no greater than 100%;

(iv) if any financial assurance remains after the allocations described in subsection (d) (iii), then that remaining financial assurance shall be allocated by repeating the steps described in subsections (d) (i), (d) (ii), and (d) (iii) to ensure that the respective test percentages are no greater than 89.99%;

(v) if any financial assurance remains after the allocation described in subsection (d) (iv), then that remaining financial assurance shall be allocated by repeating the steps described in subsections (d) (i), (d) (ii), and (d) (iii) to ensure that the respective test percentages are no greater than 79.99%;

(vi) any financial assurance that remains after the allocations described in subsection (d) (v) shall be allocated to the Market Credit Test Percentage.

2. Notices

a. 80 Percent Test

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%), the ISO shall issue notice thereof to such Market Participant.

b. 90 Percent Test

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage equals or exceeds 90 percent (90%) , then, in addition to the actions to be taken when the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%), the ISO shall issue notice thereof to such Market Participant. The ISO shall also issue a 90 percent (90%) notice to a Market Participant and take certain other actions under the circumstances described in Section III.B.2.c below.

c. 100 Percent Test

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) or when the sum of the financial assurance and credit limits of a Market Participant that has financial assurance requirements equal zero, then, in addition to the actions to be taken when the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%) and 90 percent (90%), (i) the ISO shall issue notice thereof to such Market Participant, (ii) that Market Participant shall be immediately suspended from submitting Increment Offers and Decrement Bids until such time when its Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are less than or equal to 100 percent (100%), and (iii) if sufficient financial assurance to lower the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 100 percent (100%) or, in the case of a Market Participant that has received one to five notices that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) in the previous 365 days (not including the instant notice), sufficient financial assurance to lower such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 90 percent (90%), is not provided by 8:30 a.m. Eastern Time on the next Business Day, (a) the event shall be a Financial Assurance Default; (b) the ISO shall issue notice thereof to such Market Participant, to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contacts for all Market Participants, and (c) such Market Participant shall be suspended from: (1) the New

England Markets, as provided below; (2) receiving transmission service under any existing or pending arrangements under the Tariff or scheduling any future transmission service under the Tariff; (3) voting on matters before the Participants Committee and NEPOOL Technical Committees; and (4) entering into any future transactions in the FTR system,~~; and (5) submitting an offer of Non-Commercial Capacity in any Forward Capacity Auction or any reconfiguration auction in the Forward Capacity Market,~~ in each case until such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are at 100 percent (100%) or less. In addition to all of the provisions above, any Market Participant that has received six or more notices in the previous 365 days that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage has exceeded 100 percent (100%) shall receive a notice thereof and shall be required to maintain sufficient financial assurance to keep such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage at less than or equal to 90 percent (90%). If such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage exceeds 90 percent (90%), the ISO shall issue a notice thereof to such Market Participant. If sufficient financial assurance to lower such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 90 percent (90%) is not provided by 8:30 a.m. Eastern Time on the next Business Day, then the consequences described in subsections (a), (b) and (c) of Section III.B.2.c (iii) above shall apply until such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are at 90 percent (90%) or less.

However, when a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) or 90 percent (90%), as applicable under this Section III.B.2.c, solely because its Investment Grade Rating is downgraded by one grade and the resulting grade is BBB-/Baa3 or higher, then (x) for five Business Days after such downgrade, such downgrade shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage and (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such downgrade if such Market Participant cures such default within such five

Business Day period. When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent solely because a letter of credit is valued at $0 prior to the termination of that letter of credit, as described in Section X.B, then the ISO, in its sole discretion, may determine that: (x) for five Business Days after such change in the valuation of the letter of credit, such valuation shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage; and/or (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such valuation if such Market Participant cures such default within such five Business Day period.

Notwithstanding the foregoing, a Market Participant shall neither (x) receive a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) nor (y) be suspended under this Section III.B if (i) the amount of financial assurance necessary for ~~-~~that Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to get to 100 percent (100%) or lower is less than $1,000 or (ii) that Market Participant's status with the ISO has been terminated.

3. Suspension from the New England Markets

a. General

The suspension of a Market Participant, and any resulting annulment, termination or removal of OASIS reservations, removal from the settlement system and the FTR system, ~~suspension of the ability to offer Non-Commercial Capacity or participate in a substitution auction in the Forward Capacity Market,~~ drawing down of financial assurance, rejection of Increment Offers and Decrement Bids, and rejection of bilateral transactions submitted to the ISO, shall not limit, in any way, the ISO's right to invoice or collect payment for any amounts owed (whether such amounts are due or becoming due) by such suspended Market Participant under the Tariff or the ISO's right to ~~administratively submit a bid or offer of a Market Participant's Non-Commercial Capacity in any Forward Capacity Auction or any reconfiguration auction or to~~ make ~~other~~ adjustments under Market Rule 1.

In addition to the notices provided herein, the ISO will provide any additional information required under the ISO New England Information Policy.

Each notice issued by the ISO pursuant to this Section III.B shall indicate whether the subject Market Participant has a registered load asset. If the ISO has issued a notice pursuant to this Section III.B and subsequently the subject Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are equal to or less than 100 percent (100%), such Market Participant may request the ISO to issue a notice stating such fact. However, the ISO shall not be obligated to issue such a notice unless, in its sole discretion, the ISO concludes that such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are equal to or less than 100 percent (100%).

Notwithstanding the foregoing, if a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 90 percent (90%) as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, and, but for such Increment Offers and/or Decrement Bids or such bilateral transactions, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, a notice will not be issued.

If a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, and, but for such Increment Offers and/or Decrement Bids or such bilateral transactions, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, a notice will be issued only to such Market Participant, and such Market Participant shall be "suspended" as described below.

Any such suspension as a result of one or more Increment Offers or Decrement Bids submitted by a Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, shall take effect

immediately upon submission of such Increment Offers and/or Decrement Bids or such bilateral transactions to remain in effect until such Market Participant is in compliance with the ISO New England Financial Assurance Policy, notwithstanding any provision of this Section III.B to the contrary.

If a Market Participant is suspended from the New England Markets in accordance with the provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy, then the provisions of this Section III.B shall control notwithstanding any other provision of the Tariff to the contrary. A suspended Market Participant shall have no ability so long as it is suspended (i) to be reflected in the ISO's settlement system, including any bilateral transactions, as either a purchaser or a seller of any products or services sold through the New England Markets (other than (A) Commercial Capacity and (B) Non-Commercial Capacity ~~during the Non-Commercial Capacity Cure Period~~) that cause such suspended Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the Market Participants, or (ii) to submit Demand Bids, Decrement Bids or Increment Offers in the New England Markets~~, (iii) to submit offers for Non-Commercial Capacity in any Forward Capacity Auction or reconfiguration auction or acquire Non-Commercial Capacity through a Capacity Supply Obligation Bilateral, or (iv) to submit supply offers or demand bids in any Forward Capacity Market substitution auction~~. Any transactions, including bilateral transactions with a suspended Market Participant (other than transactions for (A) Commercial Capacity and (B) Non-Commercial Capacity ~~during the Non-Commercial Capacity Cure Period~~) that cause such suspended Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the other Market Participants and any Demand Bids, Decrement Bids, Increment Offers, and Export Transactions submitted by a suspended Market Participant shall be deemed to be terminated for purposes of the Day-Ahead Energy Market clearing and the ISO's settlement system. If a Market Participant has provided the financial assurance required for a Capacity Supply Obligation Bilateral ~~or Annual Reconfiguration Transaction~~, then that Capacity Supply Obligation Bilateral ~~or Annual Reconfiguration Transaction, respectively,~~ will not be deemed to be terminated when that Market Participant is suspended.

A Market Participant's failure to satisfy Auction Delivery Financial Assurance requirements shall not constitute a suspension event under this Section III.B.3 and shall be governed exclusively by Section VIII.A.

b. Load Assets

Any load asset registered to a suspended Market Participant shall be terminated, and the obligation to serve the load associated with such load asset shall be assigned to the relevant unmetered load asset(s) unless and until the host Market Participant for such load assigns the obligation to serve such load to another asset. If the suspended Market Participant is responsible for serving an unmetered load asset, such suspended Market Participant shall retain the obligation to serve such unmetered load asset. If a suspended Market Participant has an ownership share of a load asset, such ownership share shall revert to the Market Participant that assigned such ownership share to such suspended Market Participant. If a suspended Market Participant has the obligation under the Tariff or otherwise to offer any of its supply or to bid any pumping load to provide products or services sold through the New England Markets, that obligation shall continue, but only in Real-Time, notwithstanding the Market Participant's suspension, and such offer or bid, if cleared under the Tariff, shall be effective.

c. FTRs

If a Market Participant is suspended from entering into future transactions in the FTR system, such Market Participant shall retain all FTRs held by it but shall be prohibited from acquiring any additional FTRs during the course of its suspension. It is intended that any suspension under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy will occur promptly, and the definitive timing of any such suspension shall be determined by the ISO from time to time as reported to the NEPOOL Budget and Finance Subcommittee, and shall be posted on the ISO website.

d. Virtual Transactions

Notwithstanding the foregoing, if a Market Participant is suspended in accordance with the provisions of the ISO New England Financial Assurance Policy as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant and, but for such Increment Offers and/or Decrement Bids, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, then such suspension shall be limited to (i) the immediate "last in, first out" rejection of pending individual uncleared Increment Offers and Decrement Bids submitted by that Market Participant (it

being understood that Increment Offers and Decrement Bids are batched by the ISO in accordance with the time, and that Increment Offers and Decrement Bids will be rejected by the batch); and (ii) the suspension of that Market Participant's ability to submit additional Increment Offers and Decrement Bids unless and until it has complied with the ISO New England Financial Assurance Policy, and the determination of compliance for these purposes will take into account the level of aggregate outstanding obligations of that Market Participant after giving effect to the immediate rejection of that Market Participant's Increment Offers and Decrement Bids described in clause (i).

e. Bilateral Transactions

If the sum of the financial assurance and credit limits of a Market Participant that has financial assurance requirements equals zero and that Market Participant would be in compliance with the ISO New England Financial Assurance Policy but for the submission of bilateral transactions to the ISO to which the Market Participant is a party, or if a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent as a result of one or more bilateral transactions submitted to the ISO to which the Market Participant is a party, then the consequences described in subsection (a) above shall be limited to: (i) rejection of any pending bilateral transactions to which a Market Participant is a party that cause the Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the Market Participants, such that the aggregate value of the pending bilateral transactions submitted by all Market Participants is maximized (recognizing the downstream effect that rejection of a bilateral transaction may have on the Market Credit Test Percentages, FTR Credit Test Percentages, or Transmission Credit Test Percentages of other Market Participants), while ensuring that the financial assurance requirements of each Market Participant are satisfied; and (ii) suspension of that Market Participant's ability to submit additional bilateral transactions until it has complied with the ISO New England Financial Assurance Policy (the determination of compliance for these purposes will take into account the level of aggregate outstanding obligations of the Market Participant after giving effect to the immediate rejection of the bilateral transactions to which the Market Participant is a party as described in clause (i) above). In the case of a bilateral transaction associated with the Day-Ahead Energy Market, the ISO will provide notice to a Market Participant that would be in default of the ISO New England Financial Assurance Policy as a result of the bilateral transaction, and the consequences described in clauses (i) and (ii) above shall only apply if the

Market Participant fails to cure its default by 6:00 p.m. Eastern Time of that same Business Day. In the case of a Capacity Load Obligation Bilateral, the consequences described in clauses (i) and (ii) above shall apply if the Market Participant does not cure its default within one Business Day after notification that a Capacity Load Obligation Bilateral caused the default. ~~Bilateral transactions that transfer Forward Reserve Obligations and Supplemental Availability Bilaterals are not subject to the provisions of this Section III.B.3(e).~~

4. Serial Notice and Suspension Penalties

If either (x) a Market Participant is suspended from the New England Markets because of a failure to satisfy its Financial Assurance Requirements in accordance with the provisions of the ISO New England Financial Assurance Policy or (y) a Market Participant receives more than five notices that its Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage has exceeded 100 percent (100%) in any rolling 365-day period, then such Market Participant shall pay a $1,000 penalty for such suspension and for each notice after the fifth notice in a rolling 365-day period. If a Market Participant receives a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage has exceeded 100 percent (100%) in the same day, then only one of those notices will count towards the five notice limit. All penalties paid under this paragraph shall be deposited in the Late Payment Account maintained under the ISO New England Billing Policy.

C. Additional Financial Assurance Requirements for Certain Municipal Market Participants

Notwithstanding the other provisions of the ISO New England Financial Assurance Policy and in addition to the other obligations hereunder, a Credit Qualifying Municipal Market Participant that is not a municipality (which, for purposes of this Section III.C, does not include an agency or subdivision of a municipality) must provide, for Capacity Commitment Periods occurring prior to June 1, 2028, additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation, or, for Capacity Commitment Periods beginning on June 1, 2028 and all Capacity Commitment Periods thereafter, additional financial assurance in one of the forms described in Section X below in an amount equal to its CM and SBE Financial Assurance Requirements at the time of calculation plus

Auction Delivery Financial Assurance, unless either: (1) that Credit Qualifying Municipal Market Participant has a corporate Investment Grade Rating from one or more of the Rating Agencies; or (2) that Credit Qualifying Municipal Market Participant has an Investment Grade Rating from one or more of the Rating Agencies for all of its rated indebtedness; or (3) that Credit Qualifying Municipal Market Participant provides the ISO with an opinion of counsel that is acceptable to the ISO confirming that amounts due to the ISO under the Tariff have priority over, or have equal priority with, payments due on the debt on which the Credit Qualifying Municipal Market Participant's Investment Grade Rating is based. Each legal opinion provided under clause (3) of this Section III.C will be updated no sooner than 60 days and no later than 30 days before each reconfiguration auction that precedes a Capacity Commitment Period to which such legal opinion relates, and if that update is not provided or that update is not acceptable to the ISO, the applicable Credit Qualifying Municipal Market Participant must either satisfy one of the other clauses of this Section III.C or provide, for Capacity Commitment Periods occurring prior to June 1, 2028, additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation, or, for Capacity Commitment Periods beginning on June 1, 2028 and all Capacity Commitment Periods thereafter, additional financial assurance in one of the forms described in Section X below in an amount equal to its CM and SBE Financial Assurance Requirements at the time of calculation plus Auction Delivery Financial Assurance.

~~**D. Inventoried Energy Program Financial Assurance Requirement**~~

~~Notwithstanding the other provisions of the ISO New England Financial Assurance Policy and in addition to the other obligations hereunder, if any Market Participant has submitted a Forward Energy Inventory Election approved by the ISO under Section III.K.1.1 of the Tariff, such Market Participant shall be subject to the additional financial assurance requirements of this section. Any such Market Participant must provide additional financial assurance in one of the forms described in Section X below in an amount equal to the Inventoried Energy Program Financial Assurance Requirement on or before December 1 of each program year. The Inventoried Energy Program Financial Assurance Requirement will be calculated on a daily basis for each program year, from December 1, 2023 through February 29, 2024 and separately from December 1, 2024 through February 28, 2025, as follows:~~

~~IEP Financial Assurance Requirement = MAX(0, FE_MWh - Q_MWh) * D_95 * MF * SPR~~

~~Where:~~

~~FE_MWh = is the amount of Forward Energy Inventory elected by the Market Participant;~~

~~Q_MWh = is the maximum observed physical inventory over the prior 15 days;~~

~~D_95 = is the 95th percentile of observed Inventoried Energy Days, which for the 2023-2024 and 2024-2025 program years shall be 19;~~

~~MF = is the month factor, which shall be 100% for December, 87% for January, and 26% for February; and~~

~~SPR = spot payment rate = the $/MWh rate used in the calculation of Inventoried Energy Spot Payments as described in Section III.K.3.2 of the Tariff.~~

IV. CERTAIN NEW AND RETURNING MARKET PARTICIPANTS REQUIREMENTS

A new Market Participant or a Market Participant other than an FTR-Only Customer, or a Governance Only Member whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months (a "Returning Market Participant") is required to provide the ISO, for three months in the case of a new Market Participant and six months in the case of a Returning Market Participant, financial assurance in one of the forms described in Section X below equal to any amount of additional financial assurance required to meet the capitalization requirements described in Section II.A.4 plus the greater of (a) its Financial Assurance Requirement or (b) its "Initial Market Participant Financial Assurance Requirement." A new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement must be provided to the ISO no later than one Business Day before commencing activity in the New England Markets or commencing transmission service under the Tariff, and shall be determined by the following formula:

$$FAR = G + T + L + E$$

Where FAR is the Initial Market Participant Financial Assurance Requirement and G, T, L and E are determined by the following formulas:

payments and charges associated with FTR settlement. Additionally, when the Designated FTR Participant is invoiced and the net of the charges incurred by such Designated FTR Participant for FTR transactions and the amount due to such Market Participant for FTR transactions results in a net charge, the amount of the net charge shall be added to the Designated FTR Participant's Settlement Financial Assurance until the invoice is paid.

D. Consequences of Failure to Satisfy FTR Financial Assurance Requirements

If a Designated FTR Participant does not have additional financial assurance equal to its FTR Financial Assurance Requirements (in addition to its other financial assurance obligations hereunder) in place at the time an FTR Auction into which it has bid closes, then, in addition to the other consequences described in the ISO New England Financial Assurance Policy, all bids submitted by that Designated FTR Participant for that FTR Auction will be rejected. The Designated FTR Participant will be allowed to participate in the next FTR Auction held provided it meets all requirements for such participation, including without limitation those set forth herein. Each Designated FTR Participant must maintain the requisite additional financial assurance equal to its FTR Financial Assurance Requirements for the duration of the FTRs awarded to it. The amount of any additional financial assurance provided by a Designated FTR Participant in connection with an unsuccessful bid in an FTR Auction which, as a result of such bid being unsuccessful, is in excess of its FTR Financial Assurance Requirements will be held by the ISO and will be applied against future FTR bids by and awards to that Designated FTR Participant unless that Designated FTR Participant requests in writing to have such excess financial assurance returned to it. Prior to returning any financial assurance to a Designated FTR Participant, the ISO shall use such financial assurance to satisfy any overdue obligations of that Designated FTR Participant. The ISO shall only return to that Designated FTR Participant the balance of such financial assurance after all such overdue obligations have been satisfied.

VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS

Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Forward Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy, and any Market Participant with System-Backed Export transactions (each a "Designated FCM Participant"), is required to provide

additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the "FCM Financial Assurance Requirements"). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant. This Section VII shall be effective for the Capacity Commitment Periods occurring prior to June 1, 2028. Thereafter, the provisions of Section VIII shall apply. Notwithstanding the foregoing, any financial assurance obligations that a Designated FCM Participant may have obtained in the Forward Capacity Market that is otherwise still required (e.g. Section VII.B Non-Commercial Capacity and Section VII.D Loss of Capacity and Forfeiture of Non-Commercial Capacity Financial Assurance) shall continue to be governed by this Section VII.

A. FCM Delivery Financial Assurance

Each Designated FCM Participant that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter, shall be subject to a "Corporate Liquidity Assessment" as described in this Section VII.A to determine its FCM Delivery Financial Assurance.

1. FCM Delivery Financial Assurance Calculation

A Designated FCM Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy. If a Designated FCM Participant's FCM Delivery Financial Assurance is negative, it will be used to reduce the Designated FCM Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements), but not to less than zero.

FCM Delivery Financial Assurance is calculated according to the following formula for a Designated FCM Participant that has a Capacity Supply Obligation up to and including the end of the Capacity Commitment Period associated with the fifteenth Forward Capacity Auction:

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF] – IMC – MCC

b. A Designated FCM Participant (i) that submits a demand bid into a substitution auction for a resource that is subject to a multi-year rate pursuant to Section III.13.1.3.5.4 or Section III.13.1.1.2.2.4, (ii) for which the maximum charge that would result from clearing the capacity subject to the multi-year rate election would exceed the revenue the Designated FCM Participant will receive for the relevant Capacity Commitment Period under its multi-year rate election for the resource, (iii) must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing the capacity subject to the multi-year rate election shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

c. If a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction and does not cure such default by the earlier of (i) the end of the appropriate cure period and (ii) 5 p.m. (Eastern Time) on the second Business Day prior to the start of the Forward Capacity Auction, then the defaulting Designated FCM Participant shall be precluded from submitting a supply offer or demand bid that is subject to this Section VII.F.4.

d. Upon the completion of the substitution auction, the amount to be included in the calculation of the FCM Financial Assurance Requirements for a Designated FCM Participant as described in Section VII.F.1 above shall be adjusted to reflect all charges and credits related to the purchase or sale of Capacity Supply Obligations in the substitution auction.

VIII. ADDITIONAL PROVISIONS FOR CAPACITY MARKETS AND SYSTEM-BACKED EXPORTS ~~[Reserved]~~

Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Capacity Market ("CM") that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy, and any Market Participant with

System-Backed Export ("SBE") transactions (each a "Designated Market Participant"), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VIII (such amounts being referred to in the ISO New England Financial Assurance Policy as the "CM and SBE Financial Assurance Requirements"). Notwithstanding the foregoing, Auction Delivery Financial Assurance is not a component of the CM and SBE Financial Assurance Requirements. If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated Market Participant.

For purposes of Auction Delivery Financial Assurance, Seasonal Delivery Financial Assurance, and Reconfiguration Delivery Financial Assurance calculations, Capacity Supply Obligations associated with Energy Efficiency measures shall be excluded.

A. Auction Delivery Financial Assurance

(1) Beginning with the Capacity Commitment Period beginning on June 1, 2028, and for each Capacity Commitment Period thereafter, prior to the close of each Capacity Auction Offer Window, a Designated Market Participant submitting a Capacity Offer into a Seasonal Capacity Auction must have sufficient financial assurance, which shall be referred to as "Auction Delivery Financial Assurance" ("ADFA"). ADFA is not a component of a Designated Market Participant's CM and SBE Financial Assurance Requirements, Financial Assurance Obligations, Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage, and is instead subject solely to the acceptance, partial acceptance, rejection, and suspension-related provisions of Section VIII.A(2)c. A Designated Market Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, ADFA in the calculation of its Financial Assurance Requirements under the ISO New England Financial Assurance Policy. A Designated Market Participant's ADFA requirements shall be calculated in accordance with the following formula:

$$ADFA = [\ DFAMW \times \max(UPF, 0.1) \times ESH \times PPR\ ] - CR$$

Where:

DFAMW = Delivery financial assurance MW ("DFAMW") equals the Designated Market Participant's Seasonal MRI Capacity for the

corresponding delivery month. Except that during the Capacity Commitment Periods occurring between June 1, 2028 and April 30, 2030, DFAMW is the Designated Market Participant's Transition Seasonal MRI Capacity.

ESH = Expected Scarcity Hours ("ESH"), equals the P95 expected capacity scarcity hours for the delivery month. For the Capacity Commitment Period beginning on June 1, 2028, ESH shall be based on the Net Installed Capacity Requirement. For the Capacity Commitment Period beginning on November 1, 2028, ESH shall be based on the Net Installed Capacity Requirement plus 400 MW. ESH for each subsequent Capacity Commitment Period shall be based on the system clearing result rounded to the nearest 400 MW increment of the immediately preceding like Seasonal Capacity Auction (i.e., the immediately preceding Summer Capacity Commitment Period or Winter Capacity Commitment Period).

CR = Capacity Revenue ("CR") shall be calculated using the Capacity Clearing Price from the immediately preceding like Seasonal Capacity Auction (i.e., the immediately preceding Summer Capacity Commitment Period or Winter Capacity Commitment Period), except that CR for the Capacity Commitment Periods beginning on June 1, 2028, and November 1, 2028, shall be calculated using the Capacity Clearing Price from the eighteenth Forward Capacity Auction. For Lead Market Participants with resources in Capacity Zones that had different Capacity Clearing Prices in the applicable auction, the CR shall be calculated using a weighted average Capacity Clearing Price.

A Designated Market Participant's ADFA requirements shall be 25 percent higher if such Market Participant does not meet the Capitalization requirements of Section II.A.4.

(2) **Timing.** ADFA requirements shall be published to the ISO's Financial Assurance Management system ("FAM") after the ISO calculates and provides MRI Capacity or Transition Seasonal MRI Capacity values to Lead Market Participants pursuant to the Capacity Auction Calendar. ADFA

must be satisfied, as described in Section VIII.A(2)c below, by the close of the Capacity Auction Offer Window.

a. Collateral Lock-In Period. A "Collateral Lock-In Period" shall begin on the second Business Day following publication of ADFA requirements in FAM, and ends upon the completion of the applicable Seasonal Capacity Auction. A Designated Market Participant may post financial assurance sufficient to satisfy its ADFA requirement from the time the "Collateral Lock-In Period" begins until the close of the Capacity Auction Offer Window. Once a Designated Market Participant's ADFA requirement is fully covered, financial assurance in an amount equal to the Designated Market Participant's ADFA requirement shall be reserved and unavailable for allocation to any other Financial Assurance Policy obligation during the Collateral Lock-In Period.

b. Only Letters of Credit provided under Section X.B and funds held in a shareholder account provided under Section X.A may be locked-in and applied to satisfy a Designated Market Participant's ADFA requirement. A Designated Market Participant's credit limit is not available to satisfy ADFA during the Collateral Lock-In Period. The ISO will test the sufficiency of a Designated Market Participant's financial assurance (in the form of Letters of Credit and shareholder-account funds only) against its ADFA requirement on a continuous basis until the close of the Capacity Auction Offer Window; however, to satisfy the ADFA requirement Letters of Credit must be received by the ISO no later than 8:00 a.m. Eastern Standard Time on the day the applicable Capacity Auction Offer Window closes.

c. Acceptance, Partial Acceptance, and Rejection of Capacity Offers. For purposes of this Section VIII.A(2)c, the final determination of whether a Designated Market Participant's ADFA requirement has been satisfied shall take into account the Designated Market Participant's credit limit upon the closing of the applicable Capacity Auction Offer Window. If a Designated Market Participant does not have adequate financial assurance available to satisfy its ADFA requirement, such Designated Market Participant will not be eligible to clear its full Seasonal MRI Capacity as described in this Section VIII.A(2)c. If a Designated Market Participant that does not have adequate financial assurance available to satisfy its ADFA requirement during the Capacity Commitment Periods occurring between June 1, 2028 and April 30, 2030, such Designated Market Participant will not be eligible to

clear its full Transition Seasonal MRI Capacity value in that Seasonal Capacity Auction, as described in this Section VIII.A(2)c.

(i) Full Acceptance. If, at the closing of the applicable Capacity Auction Offer Window, a Designated Market Participant's financial assurance is at least equal to the sum of (A) its other Financial Assurance Obligations and (B) its full ADFA requirement, or if financial assurance sufficient to satisfy the Designated Market Participant's full ADFA requirement is locked-in in accordance with the ADFA Collateral Lock-In Period criteria, the Designated Market Participant's Capacity Offer will be fully accepted into that Seasonal Capacity Auction, subject to the applicable auction-clearing process as set forth in Market Rule 1 Section III.15.4.

(ii) Partial Acceptance. If, at the closing of the applicable Capacity Auction Offer Window, a Designated Market Participant's financial assurance is sufficient to satisfy its other Financial Assurance Obligations in full but is insufficient to satisfy its full ADFA requirement, the Designated Market Participant's Capacity Offer will be accepted up to the amount of Seasonal MRI Capacity supported by the financial assurance available for ADFA, and the ISO shall reflect any resulting shortfall as a participant-specific MW capacity constraint within the Market Clearing Engine ("MCE"), which the MCE shall treat as a hard cap in determining the auction-clearing outcome, optimized across all other market and reliability constraints. A Designated Market Participant may designate, before the completion of the applicable Seasonal Capacity Auction, a minimum "must-take" block of its Capacity Offer as a Rationing Minimum Limit ("RML"); any portion of a Capacity Offer above the RML, or the entirety of a Capacity Offer for which no RML is designated, is treated by the MCE as fully rationable for purposes of the constraint described in this subsection (ii). If the amount of Seasonal MRI Capacity supported by available ADFA is less than the applicable Rationing Minimum Limit, the Capacity Offer shall not be eligible for partial acceptance.

(iii) Full Rejection. If, at the closing of the applicable Capacity Auction Offer Window, a Designated Market Participant has no financial assurance available to support ADFA, that Designated Market Participant's Capacity Offer into that Seasonal Capacity Auction will be rejected in full.

(iv) The adjustments described in this Section VIII.A(2)c are made entirely within the applicable Seasonal Capacity Auction's clearing process and do not reopen the applicable Capacity Auction Offer Window.

B. Seasonal Delivery Financial Assurance

Beginning with the Capacity Commitment Period beginning on June 1, 2028, and for each Capacity Commitment Period thereafter, any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy (each a "Designated Market Participant"), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VIII.B (such amounts being referred to in the ISO New England Financial Assurance Policy as the "Seasonal Delivery Financial Assurance Requirements"). Seasonal Delivery Financial Assurance Requirements shall be calculated separately for the Summer Capacity Commitment Period and the Winter Capacity Commitment Period for each Designated Market Participant with a Capacity Supply Obligation in that Capacity Commitment Period. A Designated Market Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, Seasonal Delivery Financial Assurance in the calculation of its Financial Assurance Requirements under the ISO New England Financial Assurance Policy.

Before application of the Monthly Stop-Loss, Applicable Limit, Revenue Credit Adjustment, and Minimum-Hours Amount described in Sections VIII.B.(1) through (3) below, a Designated Market Participant's Seasonal Delivery Financial Assurance attributable to a single Delivery Month is calculated in accordance with the following formula:

$$\text{Seasonal Delivery FA} = [\ \text{DFAMW} \times \max(\text{UPF}, 0.1) \times \text{ESH} \times \text{PPR}\ ] - \text{CR} - \text{IMC} - \text{MCC}$$

Where:

DFAMW	=	Equals the sum of the Capacity Supply Obligations of each resource in the Designated Market Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the Seasonal Stop-Loss described in Section VIII.B(7)(B). If the calculated DFAMW is less than zero, then the DFAMW will be set equal to zero.
UPF	=	Underperformance Factor ("UPF") equals The greater of 0.1 and the P90 of the Designated Market Participant's Underperformance Rate for the Underperformance Factor Season Group that includes the Delivery Month, as described in Sections VIII.B(5) and (6) below.
ESH	=	Equals the P95 expected capacity scarcity hours for the delivery month at the system clearing level, rounded to the nearest 400MW increment relative to the Net Installed Capacity Requirement of the applicable Capacity Commitment Period, as described in Section VIII.B(2)(D).
PPR	=	Performance Payment Rate ("PPR") equals the PPR set forth in Market Rule 1, Section III.15.8.2.5.
CR	=	Equals DFAMW for the delivery month, multiplied by the weighted average acquisition price (in $/MW month) of the portfolio applicable to the delivery month, as described in Section VIII.B(1)(F) below. CR reduces the Seasonal Delivery FA and Auction Delivery FA requirements, subject to the timing described in Section VIII.B(2)(C) below.
IMC	=	Intra-Month Collateral ("IMC") equals the estimated monthly capacity payments incurred during the current delivery month, limited by the difference (not less than zero) between (A) the minimum of the applicable

monthly stop-loss and the remaining seasonal stop-loss as described in Section III.15.8.3.1 and Section III.15.8.3.2 of Market Rule 1, respectively, and (B) the amount of additional Seasonal Delivery Financial Assurance when considering the Designated Market Participant's current month Seasonal Delivery Financial Assurance obligation as compared to the Designated Market Participant's next month Seasonal Delivery Financial Assurance obligation, in each case without giving effect to the IMC and MCC variables when calculating such additional amount. The estimated monthly capacity payments for each Designated Market Participant shall be updated three Business Days after publication of the most recent preliminary capacity performance score report (or equivalent report) on the Market Information Server.

MCC = Monthly Capacity Charge ("MCC") equals monthly capacity payments incurred in previous months, which have not yet been invoiced in instances where the MCC is a credit to the Designated Market Participant or which have not yet been invoiced and paid in instances where the MCC is a charge to the Designated Market Participant. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

(1) This single-delivery-month calculation is the building block for the full Seasonal Delivery Financial Assurance calculation: it is capped by the Monthly Stop-Loss for that delivery month as described in Section VIII.B(2)(C) below. The capped monthly amounts for the Capacity Commitment Period are then aggregated, capped again by the applicable limit (the lesser of the seasonal stop-loss and the sum of the remaining monthly stop-losses), adjusted for Capacity Revenue offsetting caps, and floored by the minimum-hours amount, all as described in subsections (2) through (4) below.

(2) Monthly Amounts. For each delivery month in the applicable Capacity Commitment Period:

(A) Underperformance Factor. The UPF applicable to that delivery month is the greater of 0.1 and the P90 (as described in subsection (5) below) of the Designated Market Participant's underperformance rate for the Underperformance Factor Season Group (as described in Section VIII.B(5) below) that includes that delivery month.

(B) Effective MW. The "Effective MW" for that Delivery Month is the Designated Market Participant's DFAMW for that delivery month, multiplied by the UPF for that delivery month.

(C) Monthly Stop-Loss. The "Monthly Stop-Loss" for that Delivery Month is the Designated Market Participant's DFAMW for that Delivery Month, multiplied by the Offer Price Cap (in $/MW month) applicable to the Capacity Auction in which the corresponding Capacity Supply Obligation was acquired.

(D) Monthly Exposure. The "Monthly Exposure" for that delivery month is the Effective MW for that delivery month, multiplied by the ESH for that delivery month, multiplied by the PPR set forth in Market Rule 1, Section III.15.8.2.5. ESH for a delivery month is the P95 expected capacity scarcity hours for that delivery month at the system clearing level of the Capacity Commitment Period that includes it, as determined by the ISO.

(E) Capped Monthly Exposure. The "Capped Monthly Exposure" for that delivery month is the lesser of the Monthly Exposure and the Monthly Stop-Loss for that delivery month.

(F) Capacity Revenue. "Capacity Revenue" for that Delivery Month is the Designated Market Participant's DFAMW for that delivery month, multiplied by the weighted average acquisition price (in $/MW month) applicable to that delivery month.

(3) Seasonal Amount. For each delivery month in the applicable Capacity Commitment Period from which the Designated Market Participant's Seasonal Delivery Financial Assurance may be assessed (an "Assessment Month"):

(A) Exposure Ahead. The "Exposure Ahead" for the Assessment Month is the sum of the Capped Monthly Exposure for the Assessment Month and for each later delivery month in that Capacity Commitment Period.

(B) Applicable Limit. The "Applicable Limit" for the Assessment Month is the lesser of the remaining Seasonal Stop-Loss described in Section VIII.B(7)(B) below and the sum of the Monthly Stop-Loss for the Assessment Month and each later delivery month in that Capacity Commitment Period.

(C) Revenue Credit Adjustment. Capacity Revenue for the Assessment Month and for the delivery month immediately following the Assessment Month shall not offset Exposure Ahead. Capacity Revenue for each delivery month that is two or more months after the Assessment Month shall offset Exposure Ahead, provided that the offset attributable to any single delivery month shall not exceed the Capped Monthly Exposure for that delivery month.

(D) Net Exposure. "Net Exposure" for the Assessment Month is the greater of zero and (I) the lesser of Exposure Ahead and the Applicable Limit, minus (II) the total Revenue Credit determined under Section VIII.B(3)(C) above.

(E) Minimum-Hours Amount. The "Minimum-Hours Amount" for the Assessment Month is the greater of zero and (1.0 minus the ESH remaining in the Capacity Commitment Period from the Assessment Month forward), multiplied by the largest Effective MW among the Assessment Month and each later delivery month in the Capacity Commitment Period, multiplied by the PPR.

(F) Monthly Requirement. The "Monthly Requirement" for the Assessment Month is the lesser of the Applicable Limit and the sum of the Net Exposure and the Minimum-Hours Amount for the Assessment Month.

(4) Seasonal Delivery Financial Assurance. A Designated Market Participant's Seasonal Delivery Financial Assurance for a Capacity Commitment Period, at any time during that Capacity Commitment Period, is the greatest Monthly Requirement determined under Section VIII.B(3)(F) above for any Assessment Month that is the current month or any later delivery month remaining in that Capacity Commitment Period, minus IMC, minus MCC.

(5) Underperformance Factor Season Groups. The Underperformance Factor is calculated separately for three "Underperformance Factor Season Groups" as follows:

(A) the "Summer Group" (June, July, August and September);

(B) the "Winter Group" (December, January and February); and~~,~~

(C) the "Shoulder Group" (May, October, November, March and April).

The Summer Capacity Commitment Period uses the Summer Group's Underperformance Factor during June through September and the Shoulder Group's Underperformance Factor during May and October. The Winter Capacity Commitment Period uses the Winter Group's Underperformance Factor during December through February and the Shoulder Group's Underperformance Factor during November, March and April. The Underperformance Factor Season Groups are distinct from, and do not align month-for-month with, the Summer and Winter Capacity Commitment Periods.

(6) Underperformance Rate and P90. For each Underperformance Factor Season Group, the ISO shall determine a dataset of underperformance rate observations for each Designated Market Participant. The dataset shall include all Performance Measurement Intervals occurring within months assigned to that Underperformance Factor Season Group during the Measurement Period.

a. The "Measurement Period" is the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period, together with any completed months, that are prior to the month immediately preceding the current month, of the current Capacity Commitment Period for which data is available. Because completed months of the current Capacity Commitment Period are incorporated into the dataset as they become available, a Underperformance Factor Season Group's P90 may change during a Capacity Commitment Period.

b. The "Performance Measurement Interval" is a five-minute interval that is either forming part of a continuous sequence of six or more consecutive five-minute intervals, each of which satisfies the Reserve Condition and the Load Condition,

or a Capacity Scarcity Condition as determined under Section III.15.8.2.1 of Market Rule 1.

i. Reserve Condition. An interval satisfies the "Reserve Condition" if the System-Wide Operating Reserve available in such interval exceeds either the Ten-Minute Reserve Requirement or the Total Operating Reserve Requirement, the latter inclusive of any Replacement Reserve Requirement then in effect, by less than one hundred (100) MW; provided that no interval satisfies the Reserve Condition solely by reason of the amount of Ten-Minute Spinning Reserve available relative to the Ten-Minute Spinning Reserve Requirement.

ii. Load Condition. An interval satisfies the "Load Condition" if total system load plus the reserve requirement in such interval is not less than the mean total system load plus the reserve requirement across all five-minute intervals occurring within months assigned to the applicable Underperformance Factor Season Group during the Measurement Period and satisfy the Reserve Condition or Capacity Scarcity Condition, less one standard deviation of that distribution.

For each Performance Measurement Interval, the "Underperformance Rate" shall equal the applicable Balancing Ratio minus the Designated Market Participant's Capacity Performance for the interval. For purposes of this calculation, the Designated Market Participant's "Capacity Performance" shall equal the Designated Market Participant's Capacity Performance Amount divided by its aggregate Current Capacity Supply Obligation. The "Capacity Performance Amount" shall equal the sum, across all resources associated with the Designated Market Participant, of each resource's Actual Capacity Provided during the interval; provided that any portion of a resource's Actual Capacity Provided in excess of its Current Capacity Supply Obligation shall be equal to the amount of the excess multiplied by a ratio of the effective PPR compared to the actual PPR. The effective PPR shall be calculated for each interval as the total system wide amount of underperformance divided by the total system wide amount of overperformance.

For Performance Measurement Intervals that are not Capacity Scarcity Conditions, the Balancing Ratio and Capacity Performance shall be determined in the same manner as prescribed for Capacity Scarcity Conditions under Section III.15.8.2.2 of Market Rule 1.

The "P90" for an Underperformance Factor Season Group shall be the ninetieth (90th) percentile of the Underperformance Rate observations contained in that Underperformance Factor Season Group's dataset.

The ISO shall establish and post on its website technology-specific default Underperformance Factor values for use only by resources that do not have sufficient performance history to support the calculation of a participant-specific P90. Updated values, if any, shall be posted prior to the commencement of the next Seasonal Capacity Auction~~.~~.

(7) Monthly Stop-Loss and Seasonal Stop-Loss.

(A) Monthly Stop-Loss for a delivery month shall be calculated as described in Section VIII.B(2)(C) above.

(B) The "Seasonal Stop-Loss" for a Capacity Commitment Period is the highest DFAMW expected to be held by the Designated Market Participant at any point during the Capacity Commitment Period, multiplied by the sum of (I) two times the Offer Price Cap (in $/MW month) and (II) four times the Capacity Clearing Price (in $/MW month), except that clause (II) shall use three times the Capacity Clearing Price for the first, truncated Summer Capacity Commitment Period.

(C) DFAMW, Offer Price Cap, and Capacity Clearing Price have the meanings used elsewhere in this Section VIII.B, applied on a Capacity Commitment Period and delivery month basis.

C. Transfer of Capacity Supply Obligations

(1) Transfer of Capacity Supply Obligations in Reconfiguration Auctions

Beginning with the Capacity Commitment Period beginning on June 1, 2028, and for each Capacity Commitment Period thereafter, a Designated Market Participant that seeks to transfer its Capacity Supply Obligation in a reconfiguration auction must include in the calculation of its CM and SBE Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the submittal window for that reconfiguration auction, as reflected in the Capacity Auction Calendar, the amounts described in subsections (a) and (b) below.

(a) For the current month and all future months, the sum of that Designated Market Participant's net monthly CM charges for each month in which the net CM revenue results in a charge. Months in this period in which that Designated Market Participant's net CM revenue results in a credit are disregarded (i.e., the net credits from such months are not used to reduce the amount described in this subsection (a)) and the current month CM charges are prorated to the proportion of remaining days in the month. The amount described in this subsection (a), if any, will increase the Designated Market Participant's CM and SBE Financial Assurance Requirements.

(b) Reconfiguration Delivery Financial Assurance. In addition to the amount described in subsection (a) above, a Designated Market Participant that seeks to acquire an additional Capacity Supply Obligation through a supply offer in a reconfiguration auction must, prior to the close of the submittal window in that reconfiguration auction, as reflected in the Capacity Auction Calendar, post financial assurance sufficient to satisfy Reconfiguration Delivery Financial Assurance ("RDFA") requirements with respect to the reconfiguration auction supply offer. RDFA is calculated in the same manner as Seasonal Delivery Financial Assurance under Section VIII.B above. RDFA shall be calculated using the MW quantity submitted in the reconfiguration auction supply offer that would result in an increase to the Designated Market Participant's Capacity Supply Obligation if cleared. If a Designated Market Participant does not post financial assurance sufficient to satisfy its RDFA requirement by the close of the submittal window in that reconfiguration auction, as reflected in the Capacity Auction Calendar, its supply offer is rejected in full.

(2) Transfer of Capacity Supply Obligations in Capacity Supply Obligation Bilaterals

Beginning with the Capacity Commitment Period beginning on June 1, 2028, and for each Capacity Commitment Period thereafter, a Designated Market Participant that seeks to transfer its Capacity Supply Obligation in a Capacity Supply Obligation Bilateral must include in the calculation of its CM and SBE Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Capacity Supply Obligation Bilateral, amounts calculated as described in Section VIII.C.1 above, as applicable. If a Designated Market Participant fails to provide the required additional financial assurance for its Capacity Supply Obligation Bilaterals, all of those transactions will be rejected. If the Designated Market Participant's request to transfer a Capacity Supply Obligation in a Capacity Supply Obligation Bilateral is not accepted, it will no longer include amounts related to that Capacity Supply Obligation in the calculation of its CM and SBE Financial Assurance Requirements.

D. Capacity Internal Bilateral Transaction Financial Assurance

A Designated Market Participant that submits a Capacity Internal Bilateral Transaction ("Capacity IBT") for the ISO to settle the floating-rate leg of a bilateral transaction between that Designated Market Participant and another Market Participant is subject to the financial assurance requirements of this Section VIII.D. A Capacity IBT does not transfer any Capacity Supply Obligation between the parties to the transaction, and submission or acceptance of a Capacity IBT does not affect either party's Auction Delivery Financial Assurance, Seasonal Delivery Financial Assurance, or Reconfiguration Delivery Financial Assurance.

On the second Business Day of each month, the ISO shall evaluate the estimated monthly settlement value of each submitted Capacity IBT ("Capacity IBT Exposure"). If a Designated Market Participant's Capacity IBT Exposure for a month exceeds the financial assurance of the Designated Market Participant in excess of its other financial assurance obligations ("Capacity IBT Shortfall"), the ISO shall notify the Designated Market Participant of the shortfall, and the Designated Market Participant shall have one Business Day to cure the shortfall. If the Capacity IBT Shortfall is not cured within one Business Day, the Capacity IBT is rejected for that month. If a Designated Market Participant's available financial assurance is sufficient to cover its Capacity IBT Exposure, or if any shortfall is timely cured, the Capacity IBT is accepted for that month, and the Capacity IBT Exposure is

added to the Designated Market Participant's financial assurance obligations until the corresponding charges are billed and paid, at which point the corresponding amount is removed from the Designated Market Participant's financial assurance obligations.

E. SBE Financial Assurance

Beginning with the Capacity Commitment Period beginning on June 1, 2028, and for each Capacity Commitment Period thereafter, a Designated Market Participant with System-Backed Export transactions, as defined in Section III.13.7.2.A and Section III.15.8.2.A of Market Rule 1, must include SBE Financial Assurance in the calculation of its CM and SBE Financial Assurance Requirements under the ISO New England Financial Assurance Policy.

SBE Financial Assurance is calculated according to the following formula for a Designated Market Participant with System-Backed Export transactions.

SBE Financial Assurance = (PPR * SBE MW * Scarcity Hours) – MEC – PMEC
Where: PPR is the Performance Payment Rate as defined in Section III.13.7.2.5 and Section III.15.8.2.5 of Market Rule 1.

SBE MW equals the Designated Market Participant's average net MW of System-Backed Exports across all Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available; provided, however, that, beginning on October 1, 2026, data from Capacity Scarcity Conditions that occurred prior to October 1, 2026 shall no longer be used once data is available from a Capacity Scarcity Condition in the relevant group of months in a prior Capacity Commitment Period or a Capacity Scarcity Condition in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.

Scarcity Hours equals the highest total number of hours in which a Capacity Scarcity Condition occurred during any month within the relevant group of months in the three

Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.

MEC (monthly export charges) equals System-Backed Export charges incurred in previous months, which have not yet been invoiced in instances where the MEC is a credit to the Designated Market Participant or have not yet been invoiced and paid in instances where the MEC is a charge to the Designated Market Participant. The MEC is estimated from the first day of the current month until it is replaced by the actual settled MEC value when settlement is complete.

PMEC (preliminary export charges) equals estimated System-Backed Export charges incurred in the current month. Where the estimated System-Backed Export charges shall be updated three (3) days after publication of the applicable report on the Market Information Server.

IX. THIRD-PARTY CREDIT PROTECTION

The ISO shall obtain third-party credit protection, in the form of credit insurance coverage ("Credit Coverage"), on terms acceptable to the ISO in its reasonable discretion at least in an amount covering collectively the Credit Qualifying Rated Market Participants based on the formula below. Notwithstanding the foregoing, if the entity providing such Credit Coverage cannot provide the amount required by this Section IX, the ISO will reduce the required coverage for all Credit Qualifying Rated Market Participants on a pro rata basis. The total amount of the Credit Coverage shall be at least the aggregate of the following formula; provided, however, if the entity providing the Credit Coverage denies coverage (in whole or in part) for any Credit Qualifying Rated Market Participant based on its rights under the insurance policy, the ISO will use reasonable efforts to obtain documentation regarding the denial and will make reasonable efforts to appeal such denial. For each Credit Qualifying Rated Market Participant, the portion of the Credit Coverage shall be the lesser of: (A) the sum of (x) 2.5 times the average Hourly Charges for such Credit Qualifying Rated Market Participant within the previous fifty-two calendar weeks plus (y) 2.5 times the sum of the average Non-Hourly Charges (excluding charges or credits related to FTR transactions) and the average Transmission Charges for such Credit Qualifying

EXHIBIT ID

ISO NEW ENGLAND BILLING POLICY

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EXHIBIT ID ISO NEW ENGLAND BILLING POLICY

SECTION 1 – OVERVIEW

Section 1.1 – Scope. The objective of this ISO New England Billing Policy is to define the billing and payment procedures to be utilized in administering charges and payments due under the Transmission, Markets and Services Tariff and the ISO Participants Agreement, in each case as amended, modified, supplemented and restated from time to time (collectively, the "Governing Documents"). Capitalized terms used but not defined in the ISO New England Billing Policy shall have the meanings specified in Section I. The ISO New England Billing Policy applies to the ISO, the Market Participants, Non-Market Participant Transmission Customers, PTOs, and Market Participants that transact only in the FTR Auction ("FTR-Only Customers") (referred to herein collectively as the "Covered Entities" and individually as a "Covered Entity") for billing and payments procedures for amounts due under the Governing Documents, including without limitation those procedures related to the New England Markets. As reflected and specified in Section 3 hereof, the ISO's obligation to make Payments (as defined below) is contingent on its receipt of sufficient aggregate Charges (as defined below) (or in cases of defaults in Covered Entities' payments of Charges, on the ISO's drawdowns under the ISO New England Financial Assurance Policy or recovery using the mechanisms specified in Section 3, 4 and 5 hereof).

Section 1.2 – Financial Transaction Conventions. The following conventions have been adopted in defining sums of money to be paid or received under the ISO New England Billing Policy:

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

b) The term "Payment" refers to a sum of money due to a Covered Entity from the ISO. Amounts due to and from the ISO include amounts collected and paid by the ISO as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

c) Where a Covered Entity's total Charges exceed its total Payments for all amounts being billed together in a billing period, the ISO shall issue an "Invoice" for the net Charge owed by such Covered Entity.

d) Where a Covered Entity's total Payments exceed its total Charges for all amounts being billed together in a billing period, the ISO shall issue a "Remittance Advice" for the net Payment owed to the Covered Entity. Invoices and Remittance Advices are collectively referred to herein as "Statements."

Section 1.3 – General Process. Except for special billings, as described in Section 1.4 below, the billing process is performed (i) twice weekly for each complete-day settlement amount for the hourly charges and payments for Real-Time Energy and Day-Ahead Energy and for each complete-day settlement amount for the hourly charges and payments for Real-Time Operating Reserve, Forward Reserves, Regulation service, Emergency Sales, Emergency Purchases, Net Commitment Period Compensation, ~~daily Forward Capacity Market charges and payments ("Daily FCM Charges")~~Daily Capacity Market Settlement, and Inventoried Energy Program charges and payments under Section III, Appendix K of the ISO Transmission, Markets and Services Tariff (all such charges and payments described in this clause (i) being referred to collectively as the "Hourly Charges"); (ii) monthly for all other charges and payments, including without limitation charges relating to the monthly markets, the monthly ~~Forward~~ Capacity Market (exclusive of settlements included in the Hourly Charges) and other ancillary services, Participant Expenses, charges under Section IV of the ISO Transmission, Markets and Services Tariff, monthly meter adjustments, Qualification Process Cost Reimbursement Deposits (including the annual true-up of those Qualification Process Cost Reimbursement Deposits), state sales tax and related charges, any pass-through charges where the ISO acts as agent (including communications related charges, Open Access Same-Time Information System related charges, and fees related to the Shortfall Funding Arrangement), and charges under the OATT (*other than* charges arising under Schedules 1, 8, and 9 to the OATT, which charges are addressed in clause (iii) below) (all such charges and payments described in this clause (ii) being referred to collectively as ("Non-Hourly Charges" and, together with Hourly Charges, as "ISO Charges"), except in the case of Covered Entities who have requested and received a weekly payment arrangement for Non-Hourly Charges under the ISO New England Financial Assurance Policy that is Exhibit IA to Section I of the ISO Transmission, Markets and Services Tariff (the "ISO New England Financial Assurance Policy"); and (iii) monthly for all charges and payments under Schedules 1, 8 and 9 to

the OATT (all such charges and payments described in this clause (iii) being referred to collectively as "Transmission Charges"). There are two major steps in the billing process:

a) *Statement Issuance*. The ISO will issue an Invoice or Remittance Advice showing the net amounts due from or owed to a Covered Entity. This Statement is determined from the preliminary statements of the New England Markets, applicable the ISO Charges and/or Transmission Charges due under the Governing Documents (including amounts due under the ISO New England Financial Assurance Policy), as well as applicable adjustments. Prior to January 1 of any calendar year, the ISO will post or make available a list of the dates in the new calendar year on which Statements will be issued, due and paid. Billing and payment holidays will be the same as the ISO's settlement holidays, as listed on the ISO's website from time to time.

b) *Electronic Funds Transfer ("EFT").* EFTs related to Invoices and Remittance Advices are performed in a two-step process, as described below, in which all Invoices are paid first and all Remittance Advices are paid later.

Section 1.4 – Special Billings. In addition to the regular billing process described above, the ISO will issue special, extraordinary Statements as and when required under the Governing Documents or in order to adjust for special circumstances. Such Statements shall be payable in accordance with the instructions set forth therein.

Section 1.5 – Conflicts with Governing Documents. Except as set forth herein, to the extent any provision hereof conflicts with any provision of any Governing Document, the provision in the Governing Document shall govern.

SECTION 2 - TIMING AND CONTENT OF STATEMENTS.

Section 2.1 – Statements for Hourly Charges. On each Monday and each Wednesday or on the following Business Day if such Monday or Wednesday is not a Business Day, the ISO shall provide electronically to each Covered Entity a Statement showing all complete-day settlement amounts for each of the Hourly Charges incurred and not reflected on a previously issued Statement. Each such Statement will cover only days with complete settled data. Accordingly,

some Statements may have fewer days of settled data for certain Hourly Charges if fewer days have been settled for those Hourly Charges on the morning of the day that such Statements are issued; a following Statement may have more days of settled data for those Hourly Charges when it becomes possible to catch up on the settled data. Statements will include contiguous month-to-month hourly market billing data and will have separate line items for any hourly market data that may cross calendar months. For example, if a Statement's billing period includes May 30 through June 2, and all of those days are fully settled, the June 8 Statement would have one line item for the period May 30 to May 31 and one line item for the period June 1 to June 2. The Job Aid on the ISO web site will be updated weekly for any information necessary to be distributed through that medium.

Section 2.2 – Monthly Statements for Non-Hourly Charges. The first Statement issued on a Monday after the ninth of a calendar month will include both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month (hereinafter sometimes referred to as a "Monthly Statement"). Resettlements determined in accordance with the procedures set forth in Market Rule 1 will be included in the monthly Statement for Non-Hourly Charges.

Section 2.3 – Statements for Weekly Billing Non-Hourly Charges. The ISO shall implement any weekly billing arrangements for Non-Hourly Charges effected under the ISO New England Financial Assurance Policy in accordance therewith and with the procedures set forth in Section 7 below.

Section 2.4 – Contents of Statements. Each Statement for Hourly and Non-Hourly Charges will include all of the following line items that are applicable to the Covered Entity receiving such Statement for the period to which such Statement relates:

a) *Invoice or Remittance Advice Amount*. The net amount of all Charges and Payments owed by or due to a Covered Entity for the relevant Statement. The ISO shall issue an Invoice where the Covered Entity owes monies. The ISO shall issue a Remittance Advice where the Covered Entity is owed monies.

b) *OATT Charges and Payments.* The Charges owed by and the Payments owed to the Covered Entity under the OATT *other than* Transmission Charges, which are billed separately under Section 2.5 below.

c) *ISO Self-Funding Charges.* The Charges owed by the Covered Entity under Section IV of the Transmission, Markets and Services Tariff, categorized by the section or schedule under which such Charges arise.

d) *Markets Charges and Payments.* The Hourly Charges owed by and the Payments for Hourly Charges owed to the Covered Entity as a result of transactions in each of the New England Markets administered by the ISO under Section III of the Transmission, Markets and Services Tariff.

e) *Monthly ~~Forward~~ Capacity Market Charges and Payments.* The Non-Hourly Charges owed by and the Payments for Non-Hourly Charges owed to the Covered Entity as a result of Capacity Performance Payments, System-Backed Export Charges, and other transactions in the ~~Forward~~ Capacity Market.

f) *Participant Expenses*. As defined in the Participants Agreement, the Covered Entity's share of costs and expenses that are incurred pursuant to authorization of the Participants Committee and are not considered costs and expenses of ISO.

g) [Reserved for Future Use]

h) *Other Amounts due under the Participants Agreement.* The Charges owed by or the Payments owed to the Covered Entity under the Participants Agreement to the extent that those amounts are not included in items (b)-(g) above.

i) *Other Non-Hourly Charges, Payments or Adjustments*. Any other Non-Hourly Charges, Payments for Non-Hourly Charges, or adjustments owed by or to the Covered Entity that are not included in items (b)-(h) above. These items may be due to retroactive billing adjustments, late payment fees, penalties or other items collectible under the Governing Documents.

j) *Billing Periods*. The billing period (from and to dates) covered for each line item on the Statement. The billing periods for the various line items are not necessarily the same because of differences in timing of settlements and because of retroactive adjustments.

k) *Payment Due Date and Time.* If the Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO.

l) *Wire Transfer Instructions*. Details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which ISO Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for ISO Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.5 – Monthly Statements for Transmission Charges. On the same date when each Monthly Statement is issued, the ISO shall provide electronically to each Covered Entity owing or owed any Transmission Charges for the preceding month a Statement (which may be combined with that Monthly Statement) showing all of the Transmission Charges for that Covered Entity for that preceding month (hereinafter sometimes referred to as a "Transmission Statement"). Any resettlements of Transmission Charges will also be included on the Transmission Statement. Each Transmission Statement will also include: (i) the billing month covered by the Transmission Statement; (ii) if the Transmission Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO; and (iii) details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which Transmission Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for Transmission Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.6 – Certain Subsequent Adjustments to Previously Issued Statements.

To: Participants Committee

From: Jasleen Singh, Secretary, Markets Committee

Date: November 6, 2026

Subject: Actions of the Markets Committee from the November 4-5, 2026 Meeting

This memo is to notify the Participants Committee ("PC") of the following actions taken by the Markets Committee (MC) at the November 4-5, 2026 MC meeting. A quorum was established.

(Agenda Item 1.A) (66.67%) Meeting Minutes

ACTION: APPROVED

The following motion was moved and seconded by the Markets Committee:

Resolved, that the Markets Committee approves the minutes for the i) October 6-7, 2026 Joint Meeting of the Markets, Reliability and Transmission Committees, ii) October 6-7, 2026 Markets Committee, and iii) September 15, 2026 Joint Meeting of the Markets, Reliability and Transmission Committees, as circulated for the November 4-5, 2026 NEPOOL Markets Committee meeting, with such further non-substantive changes as the Chair and Vice-Chair may approve.

Based on a voice vote, the motion passed with none opposed and one abstention in the End User Sector.

(Agenda Item 3.0) (60.00%) – Capacity Auction Reforms – Seasonal Accreditation (CAR-SA)

The following motion was moved and seconded by the Markets Committee:

Resolved, that the Markets Committee recommends the Participants Committee support ISO-NE's proposed Capacity Auction Reforms – Seasonal Accreditation package and related revisions to: Section I.2.2, and Market Rule 1 including Appendix A, and F and excluding III.1.5, and III.12, of the Transmission, Markets, and Services Tariff, as circulated for its November 4-5th meeting; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

(Withdrawn) (Agenda Item 3.e.i) NRG – Publication of Resource-level Marginal Reliability Impact Capacity/Capacity Supply Obligation Information

Before the main motion could be voted, the following motion was moved and seconded by the Markets Committee to amend the main motion as follows:

Resolved, that the main motion be amended to reflect changes to Sections III.15.4.3 and III.15.9 of Market Rule 1 as contained in the material provided by NRG, to require publication of resource-level Marginal Reliability Impact Capacity based Capacity Supply Obligation values; together with any further

changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The ISO noted that it would incorporate this concept as a friendly amendment to its proposal and the proponent withdrew its motion to amend the main motion.

(Vote 1 – Failed) (Agenda Item 3.e.ii) (60.00%) Constellation – Ambient Air Offer Quantity Calculation Alternative Methodology

Before the main motion could be voted, the following motion was moved and seconded by the Markets Committee to amend the main motion as follows:

Resolved, that the main motion be amended to reflect changes to Sections III.15.2.1.5 of Market Rule 1 as contained in the material provided by Constellation, to calculate the ambient air condition MW quantity as the resource's Relative Marginal Reliability Impact multiplied by the difference between its output ratings at 90°F and 100°F; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to amend was voted and, based on a roll call vote, it failed to pass with a vote of 54.17% in favor. The individual Sector votes were Generation (16.67% in favor, 0.00% opposed, 0 abstentions), Transmission (0.00% in favor, 16.67% opposed, 0 abstentions), Supplier (16.67% in favor, 0.00% opposed, 8 abstentions), Publicly Owned Entity (0.00% in favor, 16.67% opposed, 0 abstentions), Alternative Resources (16.67% in favor, 0.00% opposed, 7 abstentions), and End User (4.17% in favor, 12.50% opposed, 7 abstentions).

(Vote 2 – Failed) (Agenda Item 3.e.iii) (60.00%) Vistra – Make transition firm gas contract requirements permanent

Before the main motion could be voted, the following motion was moved and seconded by the Markets Committee to amend the main motion as follows:

Resolved, that the main motion be amended to reflect changes to Section III.15.2.1.6 of Market Rule 1 as contained in the materials provided by Vistra, to make the transition firm gas contract requirements permanent by allowing qualifying pipeline gas contracts meeting North American Energy Service Standards Board or International Swaps and Derivatives Association Gas Annex firm transportation standards to satisfy the firm fuel requirements beyond the transition; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to amend was voted and, based on a show of hands, it failed to pass.

(Vote 3 – Passed) (Agenda Item 3.e) (60.00%) Main Motion[1]

ACTION: RECOMMEND SUPPORT

The main motion was then voted and, based on a roll call vote, it passed with a vote of 78.59% in favor.[2] The individual Sector votes were Generation (3.33% in favor, 13.33% opposed, 2 abstentions), Transmission (16.67% in favor, 0.00% opposed, 0 abstentions), Supplier (13.33% in favor, 3.33% opposed, 4 abstentions), Publicly Owned Entity (16.67% in favor, 0.00% opposed, 0 abstentions), Alternative Resources (11.92% in favor, 4.74% opposed, 0 abstentions), and End User (16.67% in favor, 0.00% opposed, 1 abstention).

[1] The main motion included NRG's amendment for this vote.

[2] Following adjournment of the meeting, an error was identified in the calculation of opposing votes in the voting spreadsheet's Generation Sector. As a result, the overall percentage in favor of the main motion was updated from 79.42% to 78.59% in favor. This Actions Letter reflects the corrected Sector vote allocations and results for Vote 3.

To: Participants Committee

From: Daniel Patnaude, Secretary, Reliability Committee

Date: November 17, 2026

Subject: Actions of the Reliability Committee from the November 17, 2026 Meeting

This memo is to notify the Participants Committee ("PC") of the actions taken by the Reliability Committee ("RC") at its November 17, 2026 meeting. A quorum was established.

(Agenda Item 1.1) (66.67% Vote) Meeting Minutes

ACTION: APPROVED

The following motion was moved and seconded by the Reliability Committee:

Resolved, that the Reliability Committee approves the minutes of the following RC meetings as distributed to the committee for the November 17, 2026 meeting together with any changes agreed to at the meeting and such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee:

- October 17, 2026 RC Meeting
- November 3, 2026 RC Meeting

Based on a show of hands, the motion passed with none opposed and no abstentions.

(Agenda Item 3.1) (66.67% Vote) Central Maine Power, Greater Portland Area Transmission Project

ACTION: APPROVED

The following motion was moved and seconded by the Reliability Committee:

Resolved, that the Reliability Committee recommends that ISO New England Inc. determine that implementation of the Central Maine Power, Greater Portland Area Transmission Project – Proposed Plan Applications (PPAs) CMP-26-T01 through CMP-26-T08 from Central Maine Power as detailed in their November 9, 2026 transmittal to ISO New England and distributed to the committee for the November 17, 2026 meeting, together with a recommendation letter from ISO New England, will not have a significant adverse effect on the stability, reliability or operating characteristics of the transmission facilities of the applicant, the transmission facilities of another Transmission Owner or the system of a Market Participant.

Based on a show of hands, the motion passed with none opposed and no abstentions.

(Agenda Item 4.0) (60.00% Vote) – Capacity Auction Reforms – Seasonal Accreditation

The following motion was moved and seconded by the Reliability Committee:

Resolved, that the Reliability Committee recommends the Participants Committee support ISO-NE's proposed Capacity Auction Reforms – Seasonal Accreditation package and related revisions to Section I.2.2 of the Transmission, Markets, and Services Tariff and Market Rule 1 Sections III.1.5 and III.12, as circulated for the November 17, 2026 meeting; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve.

(Agenda Item 4.c.i) (60.00% Vote) NEPGA Amendment – Resource Re-Election Look Back Period

ACTION: WITHDRAWN

Before the main motion could be voted, the following motion was moved and seconded by the Reliability Committee to amend the main motion as follows:

Resolved, that the main motion be amended to reflect changes to Section III.12.7.3.3 of Market Rule 1 as contained in the materials provided by the New England Power Generators Association, to allow resources to re-elect its 3- or 10-year look back period every three years; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The ISO noted that it would incorporate this concept as a friendly amendment to its proposal and the proponent withdrew its motion to amend the main motion.

ACTION: RECOMMEND SUPPORT

The main motion was then voted and based on a show of hands the motion passed with none opposed and one abstention (1 Supplier).

(Agenda Item 5.2) (66.67% Vote) New England Power Line 301 345 kV Asset Condition Refurbishment Project TCA

ACTION: APPROVED

The following motion was moved and seconded by the Reliability Committee:

Resolved, the Reliability Committee has reviewed the requested $158.81 million of Transmission Upgrade costs for work associated with the New England Power Line 301 345 kV Asset Condition Refurbishment Project TCA Application NEP-26-TCA-03 submitted to ISO New England on September 25, 2026 by New England Power; and the Reliability Committee recommends that ISO New England approve, as consistent with the criteria set forth in Section

12C of the ISO New England Open Access Transmission Tariff for receiving regional support and inclusion in Pool-Supported PTF Rates, the requested $158.81 million as eligible for Pool-Supported PTF cost recovery and with none of the costs associated with such upgrades being considered Localized Costs.

Based on a show of hands, the motion passed with none opposed and no abstentions.

(Agenda Item 6.1) (66.67% Vote) OP-2 Appendix C – Equipment Maintenance Request Form

ACTION: RECOMMEND SUPPORT

The following motion was moved and seconded by the Reliability Committee:

Resolved, that the Reliability Committee recommends Participants Committee support for revision of ISO New England Operating Procedure No. 2 Appendix C as distributed to the committee for the November 17, 2026 meeting, together with such other changes as discussed and agreed to at the meeting, and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

Based on a show of hands, the motion passed with none opposed and no abstentions.

(Agenda Item 6.3) (66.67% Vote) OP-13 – Standards for Voltage Reduction and Load Shedding Capability

ACTION: RECOMMEND SUPPORT

The following motion was moved and seconded by the Reliability Committee:

Resolved, that the Reliability Committee recommends Participants Committee support for revision of ISO New England Operating Procedure No. 13 as distributed to the committee for the November 17, 2026 meeting, together with such other changes as discussed and agreed to at the meeting, and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

Based on a show of hands, the motion passed with none opposed and no abstentions.

(Agenda Item 6.4) (66.67% Vote) OP-14 Appendix I – Continuous Storage Facility Operator Guide

ACTION: RECOMMEND SUPPORT

The following motion was moved and seconded by the Reliability Committee:

Resolved, that the Reliability Committee recommends Participants Committee support for revision of ISO New England Operating Procedure No. 14 Appendix I as distributed to the committee for the November 17, 2026 meeting, together with such other changes as discussed and agreed to at the meeting, and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

Based on a show of hands, the motion passed with none opposed and no abstentions.

To: Participants Committee

From: Jill Macura, Secretary, Transmission Committee

Date: November 19, 2026

Subject: Actions of the Transmission Committee from the November 19, 2026 Meeting

This memo is to notify the Participants Committee ("PC") of the actions taken by the Transmission Committee ("TC") at the November 19, 2026 meeting. A quorum was established.

(Agenda Item 1.1) (66.67% Vote) – Meeting Minutes

ACTION: APPROVED

The following motion was moved and seconded by the Transmission Committee:

Resolved, that the Transmission Committee approves the minutes of the following TC meetings as distributed to the TC for the November 19, 2026 meeting, together with any changes agreed to at the meeting and such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee:

- October 6-7, 2026 Joint MC/RC/TC Meeting Minutes
- October 14, 2026 TC Meeting Minutes

Based on a show of hands, the motion passed with none opposed and no abstentions.

(Agenda Item 2.0) (66.67% Vote) – Capacity Auction Reforms – Seasonal Accreditation

ACTION: APPROVED

The following motion was moved and seconded by the Transmission Committee:

Resolved, that the Transmission Committee recommends the Participants Committee support ISO-NE's proposed Capacity Auction Reforms – Seasonal Accreditation package and related revisions to: Section I and Section II of the Transmission, Markets, and Services Tariff, including Section I.2.2 and Sections II.48-II.55.3 and Section II.K of the Open Access Transmission Tariff (OATT), as circulated for its November 19, 2026 meeting; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Transmission Committee may approve.

Based on a show of hands, the motion passed with none opposed and two abstentions (1 End User, 1 Generation).

memo

To: NEPOOL Markets Committee (MC), Reliability Committee (RC), and Transmission Committee (TC)

From: ISO New England, Inc.

Date: October 29, 2026

Subject: Capacity Auction Reforms – Seasonal / Accreditation (CAR-SA) Voting Memo (WMPP ID: 185)

The ISO is requesting votes on the second phase of its proposed Capacity Auction Reforms (CAR). The CAR-SA proposal introduces seasonality to capacity procurement, introduces a winter gas constraint, and incorporates accreditation reforms. This proposal builds on the broadly supported and FERC-approved Capacity Auction Reforms – Prompt / Deactivation (CAR-PD) proposal. The CAR-SA proposal will procure capacity in a more cost-effective manner that aligns with the region's resource adequacy criterion by more accurately reflecting resource operational characteristics in the resource adequacy modeling, better aligning capacity accreditation values with expected contributions to resource adequacy – including more explicit recognition of resources' fuel limitations – and running more targeted seasonal auctions.

The CAR-SA proposal moves the Annual Capacity Auctions structure to Seasonal Capacity Auctions. The introduction of summer and winter seasons allows the capacity market to specify its needs more accurately in each season in which the region experiences resource adequacy risk. This includes the development of seasonal demand curves, reflecting capacity's reliability value in each season, and allows for the determination of season-specific accreditation values for each resource that correspond with their expected resource adequacy contributions for that season.

Key modeling improvements and accreditation reforms are proposed under CAR-SA to better reflect expected resource operational characteristics and demand forecasts that align with how much capacity resources can sell, consistent with their modeled resource adequacy contributions. The modeling improvements will allow the market to continue meeting its long-term 1-in-10 resource adequacy criterion. The accreditation reforms will consider supply relative to their Marginal Reliability Impact Capacity (MRIC) quantities, which send investment signals and compensate resources based on their expected resource-adequacy contributions.

The proposal also introduces a novel winter gas market constraint and corresponding firm gas contract requirements, reflecting that the region's gas infrastructure can become constrained during cold winter spells. The constraint allows the region to cost-effectively trade off its procurement of non-firm gas resources with other capacity resources, and it helps ensure that all procured capacity will provide reliability value to the region, commensurate with its costs.

Finally, the proposal includes a measured transition mechanism to provide a glide path from current rules to those that will be in place under the full CAR-SA design. The transition mechanism will ease the industry and the region into the full CAR-SA design over several years by gradually shifting accreditation values – which includes a targeted adjustment for energy storage accreditation, making commensurate adjustments to the demand curve, and relaxing firm gas contract requirements. This will provide greater market stability, moderate initial impacts, ensure operational experience with the new design, and provide market participants time to evaluate potential changes to their participation before the full design goes into effect.

The ISO proposal is the product of robust discussion with stakeholders and incorporates numerous stakeholder-suggested revisions. The ISO began presenting on its CAR-SA proposal in early 2025[1] and has since summarized the key content areas and hyperlinked to the presented detailed design in the CAR-SA Proposal Information Summary.[2]

The ISO is proposing an effective date of March 31, 2027. Timely implementation is critical to successfully delivering a project of this magnitude. The Summer 2028 auction timeline will require deactivation submissions by June 2027, with RAA-based ICR[3] and accreditation activities beginning shortly thereafter in July. The ISO remains encouraged by the progress made to date and the strong regional and stakeholder support for the first prompt seasonal auction in May 2028.

[1] Discussions around directional design decisions began in March 2025. Detailed design discussions began in September 2025.
[2] The CAR-PD design is summarized in its own Proposal Information Summary.
[3] Resource Adequacy Assessment based Installed Capacity Requirement.